THESIS FOR THE DEGREE OF DOCTOR OF PHILOSOPHY

INTERRUPTIBLE LOAD AS AN ANCILLARY SERVICE IN DEREGULATED ELECTRICITY MARKETS

by

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ABSTRACT

Power companies world-wide have been restructuring their electric power systems from a vertically integrated entity to a deregulated, open-market environment. Previously, electric utilities usually sought to maximize the social welfare of the system with distributional equity as its main operational criterion. The operating paradigm was based on achieving the least-cost system solution while meeting reliability and security margins. This often resulted in investments in generating capacity operating at very low capacity factors. Decommissioning of this type of generating capacity was a natural outcome when the vertically integrated utilities moved over to deregulated market operations. The erstwhile objective of maximizing social welfare with distributional equity was then replaced by a profit-maximizing objective with efficiency as the main criterion for the generating companies. As a consequence, power producers are no longer responsible for the system reliability margins in deregulated markets. Additionally, new investments in generating capacity are not easily forthcoming since private investors look for a high rate of return of capital employed, which becomes increasingly difficult to ensure in a competitive environment. These factors, being a consequence of deregulation, have triggered a need for the research and implementation of interruptible load management – ILM. In an ILM program, the customer enters into a contract with the independent system operator (ISO) to reduce its demand as and when requested. The ISO benefits in having additional reserve for its security management services, while the customer benefits from reduction in energy costs and from incentives provided by the contract. Though this concept is not new, it has attained a new significance because of the deregulation.

This thesis proposes a model for a competitive market for interruptible load customers where they can offer to reduce (a part of) their demand, as an ancillary service provision to be procured by the ISO. The operational objective of the proposed market would be minimizing the total ILM procurement costs while satisfying the system operational constraints. It is shown that an interruptible load market can help the ISO to maintain the operating reserves during peak load periods. Econometric analysis reveals that a close relationship exits between the reserve level and the amount of interruptible load service invoked. It was also found that at certain buses, market power could exist which may lead to unwanted inefficiencies in the market. Investing in generation capacity at such buses can mitigate this.

The thesis also examines the role of interruptible load during contingencies and peak demand in the power system. In particular the ability of the interruptible load market in providing transmission congestion relief is analyzed. In the proposed congestion management scheme, interruptible loads can specifically identify those load buses where corrective measures are needed for relieving congestion in a particular transmission corridor.

While examining the role of interruptible load in providing for congestion management, it is necessary to arrive at a long-term solution for persistent congestions, i.e., bottlenecks in the system. An answer to this, is investment in reserve generation at strategic locations in order to provide for efficient congestion relief. Long-term investment needs for fast start-up generators that can alleviate transmission bottlenecks and provide additional operating reserves were investigated by a comprehensive cost-benefit analysis and a least-cost optimization scheme.

Keywords: deregulated electricity market, interruptible load management, ancillary services, congestion management, reserve generation, optimal power flow, least-cost planning.

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In peer-reviewed journals:

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LIST OF SYMBOLS AND ACRONYMS

i,j,k	Bus index
h	Hour index
Type	Customer type index
CI	Congestion index
CL	Compensation for loss, $/p.u. MW
GT	Gas turbine capacity, p.u. MW
L	Total system loss, p.u. MW
LS	Load share of a customer Type at a bus, %
LSF	Hourly load scaling factor
N	Total number of buses
NG	Total number of generating buses
NT	Total number of transmission lines
NGT	Total number of gas-turbine generators
NL	Total number of load buses
NILM	Total number of ILM buses
PD	Real power demand, p.u. MW
PD_m	Real power demand on spot market, p.u. MW
PD_b	Real power demand on bilateral contract, p.u. MW
PDem	Real power demand by customer type, p.u. MW
PF	Power factor of load
PG	Real power generation, p.u. MW
PG_m	Real power generation for sale on spot market, p.u. MW
PG_b	Real power generation for bilateral contract, p.u. MW
PG^{max}, PG^{min}	Real power generation limits, p.u. MW
PGcon	Contracted generation, p.u. MW
PVIOL	Violated transmission capacity, p.u. MW
ΔPD	Real power interruption, p.u. MW
ΔQD	Reactive power relieve, p.u. MW
QC	Reactive power compensation, p.u. MVAr
QC^{max}, QC^{min}	Reactive power compensation limits, p.u. MVAr
QD	Reactive power demand, p.u. MVAr
RES	Operating reserve margin requirement, p.u. MW
RLIM	Reserve limit above which interruptible load market is not required to operate, p.u. MW
U	Binary variable denoting the selection of an interruptible load contract
UC	Unit commitment decision, 0/1

UG	Binary variable denoting the selection of a gas-turbine generator
UE	Unserved energy, p.u. MW
V	Bus voltage, p.u.
V^{max}, V^{min}	Upper and lower limits on bus voltage, p.u.
VC	Transmission violation cost, \$/p.u. MW
Y	Element of network admittance matrix, p.u.
Y_{ch}	Charging admittance matrix, p.u.
B	Element of susceptance matrix, p.u.
θ	Angle associated with Y, radianVoltage angle, radian
λ	Marginal loss coefficient at a bus, p.u. MW/p.u. MW
β	interruptible load offer price, \$/p.u. MW
μ	Interruptible load offer quantity, p.u. MW
ρ	ISO pay price to selected interruptible load offers, \$/p.u. MW
a_0	Scalar multiplier denoting the fraction of total demand of a particular load type at a bus, at its disposal
a_1, a_2	Scalar multipliers

UEC	Cost of unserved energy
BCR	Benefit-to-Cost Ratio
CRM	Congestion Relief Model
CRI	Congestion Relief Index
DSM	Demand-side Management
ISO	Independent System Operator
ILM	Interruptible Load Management
OPF	Optimal Power Flow

CONTENTS

CHAPTER 1

INTRODUCTION

This chapter presents a brief overview of power industry deregulation and the situation in Sweden in this regard. Various implications of deregulation, such as decreasing reserve margins, price volatility, and lack of incentive for investment in generation capacity, are discussed. In this context, interruptible load management is gaining increasing importance as a means for additional operating reserve in the system. The objectives of this study, aimed at addressing various issues related to operating of the interruptible load management programs in deregulated electricity markets are laid out. A brief outline of various chapters of this thesis is also provided.

1.1 Deregulation of the Electricity Supply Industry

Since the last two decades, many electric utilities world-wide have been forced to change their ways of doing business, from vertically integrated functioning to open-market systems. The reasons have been many and differed across regions and countries.

In developing countries, the main issues have been high demand growth associated with inefficient system management and irrational tariff policies, among others. This has affected the availability of capital investment in generation and transmission systems. In such a situation, many countries were forced to restructure their power sectors under pressure from international funding agencies. On the other hand, in developed countries, the driving force has been to provide the customers with electricity at lower prices and to offer them greater choice in purchasing electricity.

Deregulation was undertaken by introducing commercial incentives in generation, transmission and distribution of electricity. The main objective of deregulation is to achieve a clear separation between production and sale of electricity, and network operations. The erstwhile vertically integrated system operation has been separated into independent activities. The generation companies sell energy through competitive long-term contracts with customers or by bidding for short-term energy supply at the spot market.

On the other hand, with significant levels of "economy of scale", it was natural for the transmission sector to become a monopoly. It was therefore necessary to introduce regulation in transmission so as to prevent it from overcharging for its services. Consequently, the transmission grid has to be a neutral monopoly subject to regulation by public authorities. New regulatory framework has been established to offer third parties "open access" to the transmission network so as to overcome the monopolistic characteristics of transmission.

In this deregulated environment, a system operator is assigned the central coordination role with the responsibility of keeping the system in balance, *i.e.*, to ensure that the production and imports continuously match the consumption and export. It is required to be an "independent" authority without any involvement in the market competition nor owning any generation facility for business (except some for emergency use). Hence its name Independent System Operator, largely known as ISO.

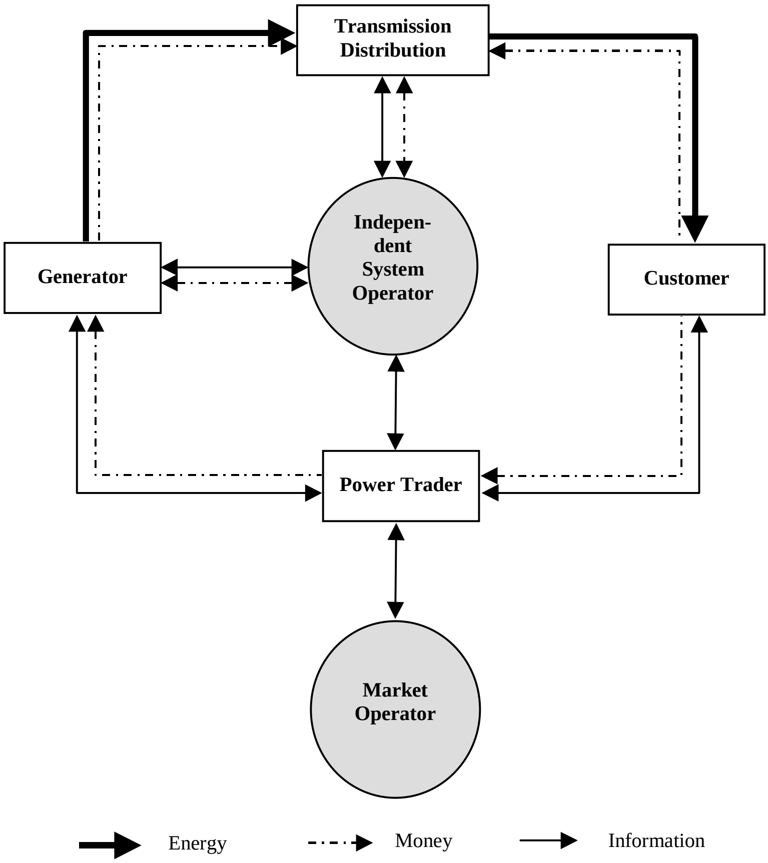

Figure 1-1: Typical structure of a deregulated power system

Figure 1-1 shows a typical structure of a deregulated power system with the complex interactions amongst different actors in the system.

Among the countries whose electricity supply industry has been deregulated, the South American countries, including Chile, Argentina, Bolivia, Colombia, Peru, and Brazil were the initiators of deregulation in, as early as, 1982. The United Kingdom, Norway, Australia, New Zealand, United States, Sweden and other European countries have subsequently opened up their power sectors to competition in the nineties. It should, however, be noted that the form of deregulation differs in each country and even among various systems in the United States.

1.2 The Swedish Electricity Market

The Swedish electricity market was reformed on January 1, 1996 when competition was introduced regarding production and sales of electricity. The Swedish market now consists of electricity producers, final customers, network owners, power trading companies, and an ISO, Svenska Kraftnät, which also manages the national high voltage transmission network. Some of the characteristic features of the Swedish market are as follows [1]:

- *Final electricity customers*, everything from industries to households, must have an agreement with an electricity supplier in order to be able to buy electricity.
- The production plants are owned by the *electricity producers*. In Sweden, about half the power produced is hydropower and the other half nuclear power.
- *A power trading company* can have several roles: that of an electricity supplier as well as a balance provider. Further, the power trading company can either have the balance responsibility itself or purchase this service from another company. The power trading company can purchase power on Nord Pool or directly from an electricity producer or another trading company.
- *The network owners* are responsible for transmitting the electrical energy from the production plants to the consumers. This is achieved though the national grid, the regional networks and the local networks, which are all owned by different network companies. The regional networks transmit power from the grid to the local networks and sometimes to major consumers, for instance industries. The local networks distribute power to the final customers within a certain area. All network owners report their consumption and production measurements to Svenska Kraftnät's settlement system.

- Svenska Kraftnät owns the national grid and has the role of *independent system operator*. This means that it ensures that production/imports correspond to consumption/exports and that the Swedish electricity plants work together in an operationally reliable way.

1.2.1 Reduced Operating Margins

In the erstwhile vertically integrated utilities, the system operator sought to maximize the social welfare with distributional equity (meeting the load at all time) as the main criteria, for the system as a whole. The operating paradigm was based on achieving the system solution while meeting reliability and security margins. This often led to investments in such generating capacity that operated at very low load factors. As a result, the prices charged to customers would be high, since the utility required to recover its operational and investment costs.

Decommissioning of generating capacity, particularly those operating at low load factors, was thus an expected outcome when such vertically integrated utilities moved over to deregulated market operations. As can be seen from Figure 1-2, in Sweden, several generating units have closed down since 1996. About 2000 MW capacity was decommissioned in 1998 and about 1200 MW in 1999. Most of these units were gas based or condensing power units and were primarily being used for peak hour generation, and had high operating costs [2].

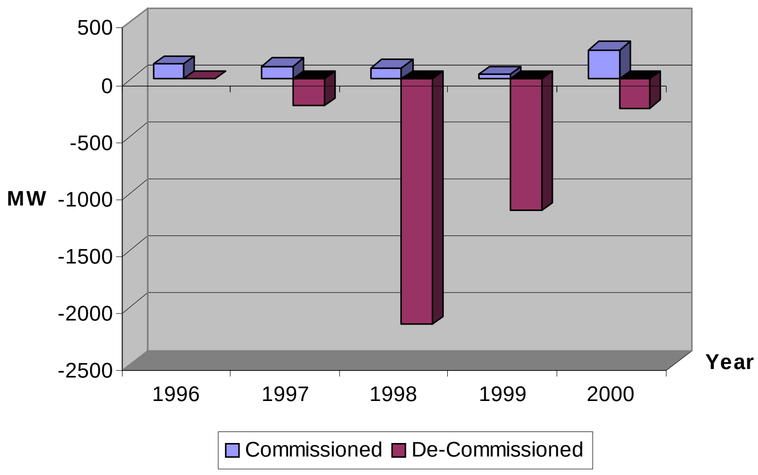

Figure 1-2: Capacity addition versus decommissioning in Sweden, after deregulation (Source: Swedish National Energy Administration, http://www.stem.se)

Figure 1-3 shows the average monthly market prices in Nordpool for the Swedish market from 1996 (since its participation in Nordpool). The first year of the reformed electricity market in Sweden was a dry year, and the system price rose up to the end of the year. The price then dropped sharply until the end of 2000. The drop in price was mainly due to the abundant precipitation (hydro energy) during these years, and also to a high level of competition among suppliers for attracting higher energy supply shares in the market and attracting customers, in the initial years. However, since the costly generation capacity could not sustain such low market prices, as shown in Figure 1-3, capacity decommissioning was the outcome. One of the reason for the subsequent increasing trend in average monthly market prices (Figure 1-3) since 2001 could be attributed to the resultant decrease in system operating margins which has acted as a signal to the major players. The other reason for that was because of the low levels in water reservoirs, for example during the period between January and April of 2003, while this is a high demand season due to the cold weather. It can therefore be noted that the spot price has well reflected the demand and supply condition in the market.

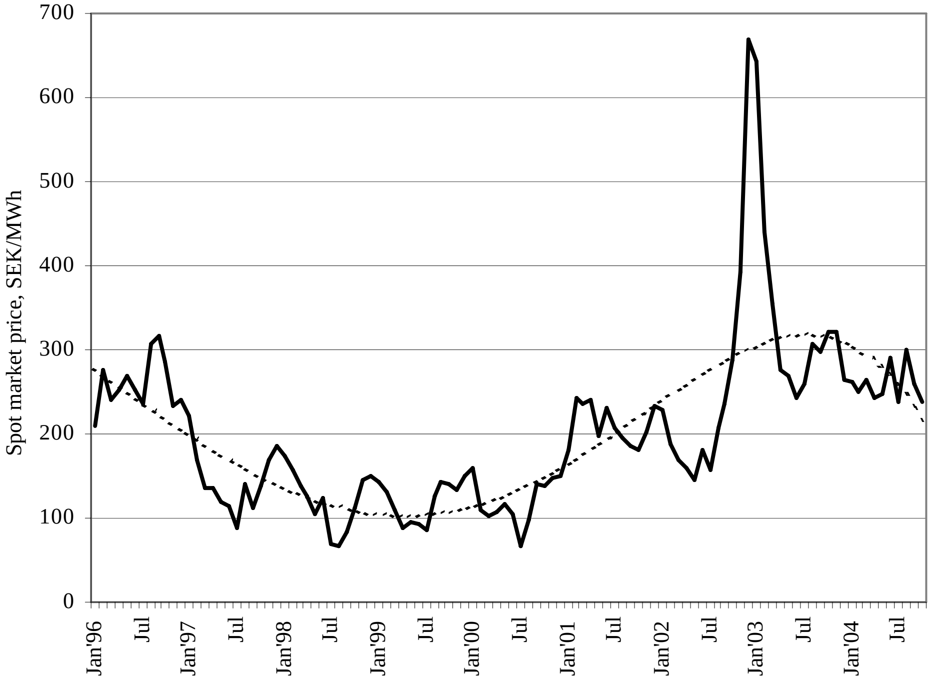

Figure 1-3: Spot market price in Nordpool for the Swedish electricity market (Source: Nordpool ASA, http://www.nordpool.no)

Figure 1-4 shows the total system capacity and total system load from 1996 to 2005 (2005 is forecast data). It is seen that there is very little new generating capacity planned for, during this period, while some more generating capacity is scheduled to be closed down. As a result, total system capacity has been decreasing, while the total system demand is increasing, thus making the system reserve margin lower.

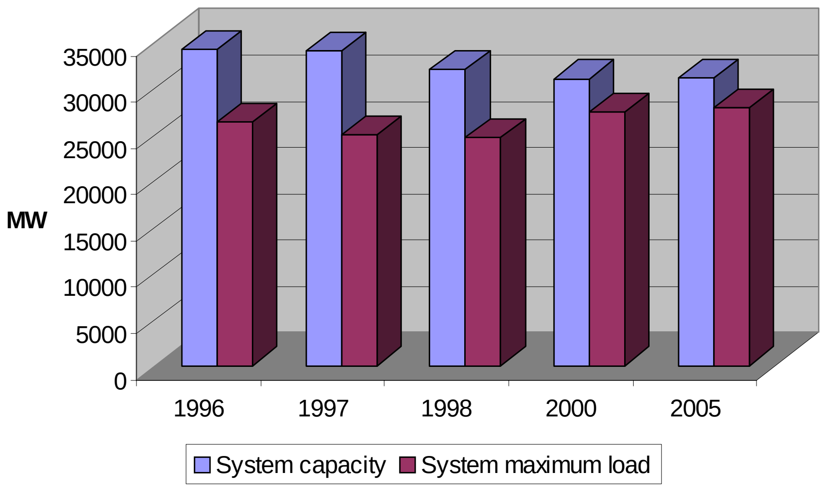

Figure 1-4: Sweden: The system margin is decreasing.

(Source: Swedish National Energy Administration, http://www.stem.se).

It should be noted that in deregulated electricity markets, new investments in generating capacity are not easily forthcoming since these are prerogatives of private investors who look for a high internal rate of return on a project, and that becomes increasingly difficult to ensure in competitive markets with uncertainties in market prices and other associated risks. This has an adverse impact on generation capacity addition in the system and leads to operating the system with very low security margin.

1.3 Interruptible Load Management (ILM)

In response to the reducing operating margins, particularly so in deregulated markets, interruptible loads could act as a useful tool for the ISO that can be invoked at times of critical system conditions, and provide the much needed system demand reduction and an operating reserve that can be activated within a short time.

In an interruptible load program, the customer signs a contract with the local utility or the ISO, as the case may be, to reduce its demand as and when requested (Figure 1-5). The utility benefits by way of reduction in its peak load and thereby saving costly generation reserves, restoring quality of service and ensuring reliability. The customer benefits from reduction in its energy costs and particularly from incentives provided by the local utility or the ISO. Provisions also exist in certain markets for the customers to offer their ability to modify their demand, which is referred to as *demand-side bidding*.

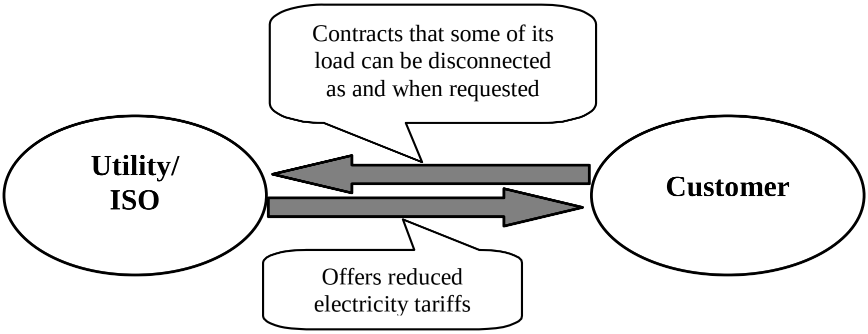

Figure 1-5: A typical interruptible load scheme

1.3.1 ILM as an Interest to Different Players in the Electricity Market

With power systems now operating under a capacity scarcity regime, in contrast to operating in classical vertically integrated and usually over-invested systems, energy efficiency and load management have assumed increasing importance. Even if prices are high during peak hours, uncertainty related to future profit has the consequence that the willingness to invest in peaking capacity, needed only occasionally, is very low. This has increased the interests among different market participants to offer load management and energy efficiency programs in a well functioning market. Incentives for interruptible load management can be derived by various players and actors in the market as described below:

- *Customers*: Customers are motivated by the potential of reducing energy costs, additional incentives from the utility, the possibility of freedom of choice and new customer services.
- *Electricity providers*: The electricity provider would be motivated by the possibility of diversification into new profitable business areas and

customers services. Utilizing customer flexibility in order to reduce procurement costs in periods of high spot prices is another incentive.

- *Grid companies*: Grid companies are motivated by reduced marginal losses, improved utilization time, postponed investments and improved quality of services.
- *System operator*: The system operator is motivated by the possibility of improved operational reliability by including the demand interruption as a reserve for peak power reduction and for the provision of ancillary services.

1.3.2 Issues in Interruptible Load Management

A. Tariff Design

Most often, the problem lies in devising the rate structure, which should be incentive compatible to both utility and customer *i.e.*, minimize utility's costs and maximize the economic benefit of customer. Implementation of interruptible tariff involves unbundling electricity services and offers customers a range of rate reliability choices. Therefore, finding optimal utility-customer interactions and contracts is similar to finding the equilibrium point in an economic analysis to determine the market price and quantity. There exist some oscillations to reach the equilibrium point. These oscillations depend on the qualitative and the quantitative response of the suppliers and the customers and estimation of these responses are critical. It is important to estimate the potential of an ILM program to reach the equilibrium point. Updating the incentive rate design with the potential estimates is the crux of devising an ILM program [3].

B. Market Design

Although most present day interruptible contracts are pre-specified in advance, energy market-place transactions can also allow for more frequent updates like one-hour spot-price, calculated based on system operating conditions and forecasts of how much interruptible energy will be purchased from customers. Customers, who choose to sell interruptible energy, do so by communicating the secure energy level they can offer [4]. Also, in an electricity market some generating companies could offer low cost but rather inflexible units while other may opt for more expensive but highly flexible generation. Even customers could be given the opportunity to offer their ability to reduce their demand during periods of peak prices. This diversity of options helps to clear the market at a lower price.

Therefore, appropriate design of the market where the customers can participate in the ILM programs is very important. The customers may choose to have a direct contract with the ISO or may opt to participate and offer its demand reduction directly in the spot market or in the balance market.

C. Program Implementation

Once the market for interruptible load has been established, it is important that the market can function efficiently and is fair to all participants. The issues related to implementation of the ILM program would include setting up of the information technology infrastructure to ensure timely information flow from the ISO or the utility to the various ILM participants, the installation of real-time meters at the customer-side to monitor that real-time interruption schedules are fulfilled and payment activities are coordinated.

1.3.3 The Importance of Price-Responsive Demand

It is desirable that the customers should have the opportunity to see electricity prices on a hour-to-hour basis, reflecting market price variations. This will improve the efficiency, increase reliability, and reduce the environmental impacts of electricity production.

Customers who choose to face the volatility of electricity prices can lower their electricity bills as they can modify electricity usage in response to changing prices: i) by increasing usage during low-price periods, and ii) by cutting down usage during high-price periods. Customers who modify their usage in response to price volatility help lower the size of price spikes.

This demand-induced reduction in prices is a powerful way to mitigate the market power that some generators would otherwise have when demand is high and supplies tight. And these price-spike reductions are beneficial to all retail customers, not just those who modify their consumption in response to changing prices [5].

Figure 1-6 shows the hypothetical demand and supply curves. The solid vertical line represents demand that is insensitive to price; the dashed line represents demand that varies with price. For the latter case, the consumers responding to price (*i.e.*, elastic demand) reduce the demand from Q_{inel} to Q_{el} and thus brings about a reduction in the price from P_{inel} to P_{el} (which is quite low if the price elasticity of demand is high).

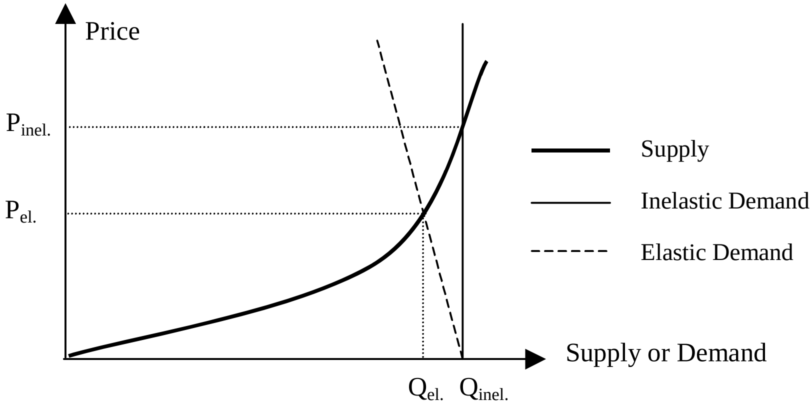

Figure 1-6: Hypothetical demand and supply curve

Customers who face real-time prices and respond to those prices provide valuable reliability services to the local control area. Reference [6] has noted that “to improve the reliability of electricity supply, some or all electric customers will have to be exposed to market prices”. Specifically, load reductions at times of high prices (generally caused by tight supplies) provide the same reliability benefits as the same amount of additional generating capacity (but at a lower cost).

Finally, strategically timed demand reductions decrease the need to build new generation and transmission facilities. When demand responds to price, system load factors improve, increasing the utilization of existing generation and reducing the need to build new facilities. Deferring such construction may improve environmental quality. Cutting demand at times of high prices may also encourage the earlier retirement of aging an inefficient generating units.

1.3.4 Interruptible Load versus Demand-side Management

Demand-side management is the planning and implementation of the utility activities designed to influence customer use of electricity in ways that will produce desired *long-term* changes in the utility's load shape. Figure 1-7 shows different load shape objectives of demand-side management program. These include: peak clipping, valley filling, load shifting, strategic conservation, strategic load growth and flexible load shape.

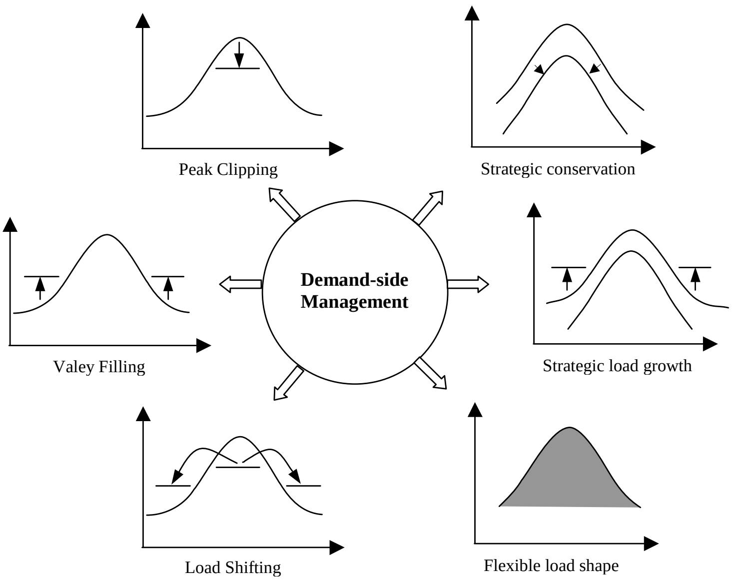

Figure 1-7: Demand-side management objectives [7]

As described in the previous section, interruptible load program is an option within a demand-side management program that provides incentives to customers for reducing their power demand during the system peak load period or emergency conditions.

1.3.5 Interruptible Load versus Fast-Startup Generator

One may ask: "Is there any difference between interrupting a load and putting online a fast-startup generator (FSG)?". There are several differences:

- The interruptible load can be available everywhere in the system, while the FSG can only be installed at limited locations. Hence, interruptible load provides the ISO with a wide range of selection in the network.
- Besides providing active power reduction, interruptible load also provides the system with "free" reactive power relief.
- FSG involves a large capital investment while that for interruptible load is much less. The utilities do, however, have to pay financial incentives to

the ILM participants. For a long-term plan, it would require a detailed economic analysis to clearly identify the cheaper option.

- FSG has to run more than a "must-run" hours requirement, while the interruptible load can only be run within some specified hours.

1.4 Objectives of the Thesis

The study presented in this thesis attempts to:

- Provide an understanding of the theoretical and practical aspects of interruptible load management in deregulated system operations;
- Design a market for interruptible load customers who are willing to reduce their demand, as and when requested, in return of a financial compensation;
- Examine the operational roles of interruptible load in cases of contingencies and demand spikes in the system; examine the market power of interruptible load bidders who take advantages of their strategic locations.
- Provide an understanding of the theoretical and practical aspects of congestion management in deregulated system operations;
- Examine the possibility of interruptible load in providing transmission congestion relief;
- Carry out a cost-benefit analysis of long-term congestion management solution through the investment in reserve generation capacity and least-cost investment in reserve services.

1.5 Outline of the Thesis

Chapter 1 provides an overview of the interruptible load management within the context of deregulated electricity market. The importance and rationale for interruptible load services are presented. The objectives of this study toward resolving different existing issues related to operating of the interruptible load management program in the deregulated electricity market are presented

Chapter 2 addresses the importance of operational roles of interruptible load management programs, namely, Direct Load Control; Dynamic Tariff/Pricing; Incentive Compatible Contract; Callable Forwards; Demand-Side Bidding; Specific ILM Markets; Priority Pricing.

Chapter 3 discusses the overall picture of the interruptible load management programs of various electric utilities, electricity markets and independent system operators around the world. The working mechanisms of interruptible load management programs and their effectiveness in aiding system operation in peak load periods and contingencies are discussed.

Chapter 4 deals with optimal procurement of interruptible load services within secondary reserve ancillary service markets in deregulated power systems. The proposed model is based on an optimal power flow framework and can aid the Independent System Operator (ISO) in real-time selection of interruptible load offers. The structure of the market is also proposed for implementation. Various issues associated with procurement of interruptible load such as advance notification, locational aspect of load, power factor of the loads, are explicitly considered. It is shown that interruptible load market can help the ISO maintain operating reserves during peak load periods. Econometric analysis reveals that a close relationship exits between the reserve level and amount of interruptible load service invoked. It was also found that at certain buses, market power exists with the loads, and that could lead to unwanted inefficiencies in the market. Investing in generation capacity at such buses can mitigate this.

Chapter 5 provides a comprehensive review of utility practices as well as research methods in the area of transmission congestion management in deregulated electricity markets. It can be seen in the paper that many electricity markets are utilizing the methods which are widely addressed in the literature of the power engineering community. However, the methods used are widely different from one another as a result of different congestion management objectives in various electricity markets.

Chapter 6 illustrates the role of interruptible load as a system service for transmission congestion management through the development of a Congestion Relief Model. The model is able to locationally identify the buses where corrective measures need to be taken for relieving congestion over a particular congested line. The *N-1* contingency criterion has been taken into account to simulate various cases and hence examine the effectiveness of the proposed method. It has been shown that the method can assist the ISO to remove the overload from lines in both normal and contingency conditions in an optimal manner.

Chapter 7 develops a framework for the evaluation of the long-term congestion management solution by the "fast-startup" gas-turbine generators based on the traditional cost-benefit analysis. This involves a planning exercise to determine the location and size of gas-turbine generators at different buses in the network such that the total cost of investment in gas-turbine generators and the cost of system congestion are minimized. The second part of this chapter utilized the least-cost planning method in the evaluation of the investment of the "fast-startup" gas-turbine generators in order to provide for reserve as well as congestion management ancillary services. In the first part, transmission congestion was used in the objective function, but not as a hard constraint, we experienced the problem that congestion was not totally removed. In the other method power flow constraints are introduced to completely remove the transmission congestion.

Chapter 8 summarizes the main results of the present work and discusses future scope of work in interruptible load markets.

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CHAPTER 2*

INTERRUPTIBLE LOAD MANAGEMENT IN SYSTEM OPERATIONS

This chapter addresses the importance of operational roles of an interruptible load management (ILM) program, with special emphasis on deregulated electricity markets. ILM programs have been classified into: Direct Load Control; Dynamic Tariff/Pricing; Incentive Compatible Contracts; Callable Forwards; Demand-Side Bidding; Specific ILM Markets; and Priority Pricing Mechanism. These are summarized in Figure 2-1:

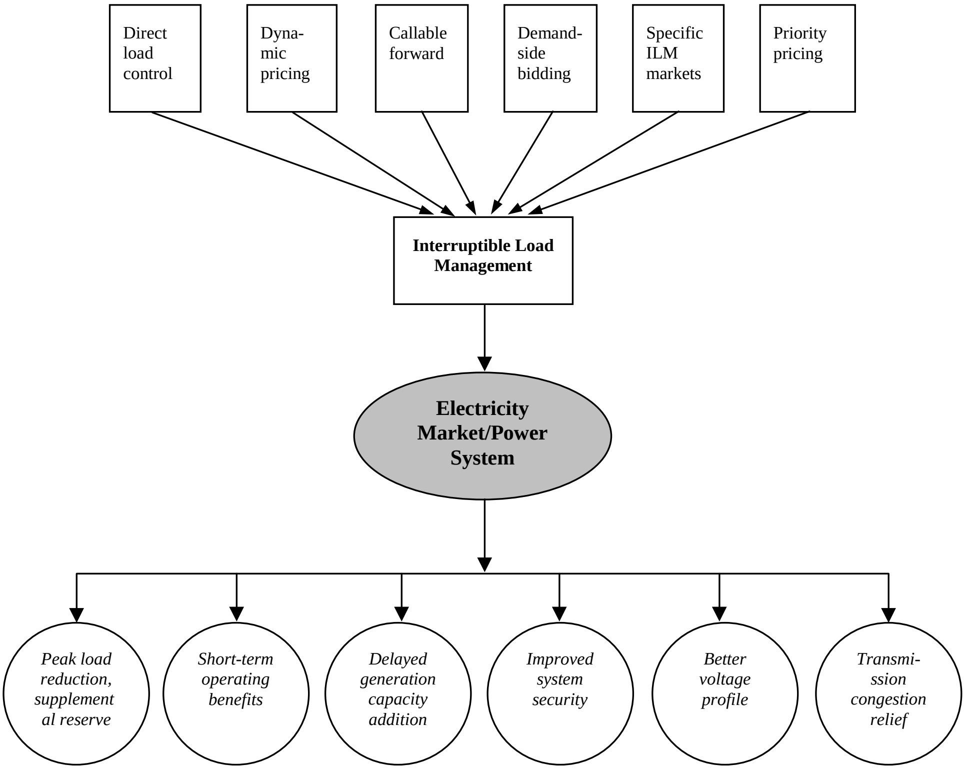

Figure 2-1: Interruptible load management and its roles in system operations

* The work contained in this chapter has been published in the following paper:

L.A. Tuan, K. Bhattacharya, "A Review on Interruptible Load Management: Literature and Practice", in Proc. of 33rd North American Power Symposium, Texas, USA, October 15-16, 2001, pp. 406-413.

2.1 Interruptible Load Management in System Operation

In order to be an effective means of managing peak load by the utility/ISO, an ILM program must adequately address the following issues [1]:

1. What are the short-term discounts in prices (in $/MWh) to be offered to the customers participating in the ILM program?
2. What are the longer-term benefits to be given to the customers in terms of reduction in demand charges (in $/MW) for the part of the demand subscribed to ILM?
3. How does the utility select different types of interruptible load in real-time taking into account the following considerations:
   - *advance notification for load curtailment*: one hour, one day, one week.
   - *duration of curtailment*: curtailment limited to peak hour only, or longer period curtailment by shifting load to off-peak hours.
   - *nature of load and cost associated with load curtailment*: low power factor with lower cost of curtailment.
   - *generation and network characteristics*: spatial demand and generating sources, limits on generation output, ramp rate, voltage, or line flows.
   - *system security*: to ensure that the system can "survive" a specified list of contingencies, *i.e.*, the emergency limits on voltage and line flow limits are not exceeded for certain line, bus or generator outage combinations.

A study on system peak demand reduction due to different load control programs in the case of the Taiwan power system was presented by Chen and Leu [2]. The avoided-cost of capacity addition for the utility and appropriate incentive rate structures to the customers were discussed in the paper.

Impact of load management on short-term operating benefit was addressed in [3]. It was shown in the paper that the interruptible load program resulted in great cost saving in terms of reducing the total societal cost (system operating cost and customer interruption cost) of electricity.

The role of interruptible load in providing supplemental operating reserve to the system was studied in [4]-[9], where a number of techniques are presented to include interruptible load in the probabilistic assessment of the level of system operating reserve. An adequate operating reserve is required in an electric power system in order to maintain a desired level of reliability throughout a given period of time. Interruptible load can be considered as part of the system operating reserve if required. The inclusion of interruptible load in the assessment of unit commitment in interconnected systems was demonstrated in [6] and of economic load dispatch of generation systems in [7].

An optimal power flow framework developed by Majumdar *et al.* [1] addressed issues of advance notification for load curtailment as well as short- and long-term price discounts on demand charges. It was shown in [10] that the interruptible tariff mechanism would be able to aid system operation during peak load periods, such as increased reliability margins, improving voltage profiles as well as relieving network congestion. A mathematical model was developed to express the response of customers to incentives offered by the utility and the OPF framework was modified to incorporate various utility-customer interactions while determining the optimal incentives.

Caramanis *et al.* [11] worked out a comprehensive pricing formulation for interruptible loads and assignment of power pool reserves. It was shown that optimal pricing mechanisms did exist, and these invoked customer participation in a socially optimum manner to aid in system operation and provide for system security. Consequently, it was shown by Kaye *et al.* [12] that system security could be maintained in an operating environment where all participants (including those on the supply-side and those on the demand-side) sought to optimize their own benefits through pricing mechanisms. A generalized model for the inclusion of security constraints in competitive markets was developed in [13] where the prices are determined by considering customer demand-price elasticity.

The role of demand elasticity in congestion management and pricing in a competitive electricity market was investigated in [14]. The actions of price responsive loads could be represented in terms of the customers' willingness-to-pay. From each customer's demand curve, the elasticity of the load at different prices is known and the benefit function is derived. The load at each bus ceases to be a fixed quantity and becomes a decision variable in the ISO's optimization problem. In this way, the ISO has additional degrees of freedom in determining necessary actions for network congestion management.

As the electric power industry moved towards deregulation and competition, the generating capacity margins available to the system operators have been reducing drastically. There is an emerging question as to “Who should be responsible for generation capacity addition?”, explicitly addressed in Söder [15], at least for the case of the Swedish deregulated electricity market. It was suggested that one of the possible measures would be to develop a market for voluntary demand reduction, *i.e.*, the interruptible load market, where the customers would be compensated for the costs of electricity service interruption.

2.2 ILM Programs, Mechanisms, and Markets

A number of methods for designing optimal working mechanisms for interruptible load participation has been proposed in the research literature. These can be divided into several groups, namely direct load control, dynamic/interruptible tariff, incentive compatible contracts, callable forwards, demand-side bidding, specific ILM markets, and priority pricing mechanism. We briefly discuss them in the following subsections.

2.2.1 Direct Load Control

The amount of system peak load reduction through scheduling of control periods in commercial/industrial and residential load control programs at Florida Power and Light Company have been calculated using a linear programming (LP) optimization model [16]. The LP model can be used to determine both long- and short-term control scheduling strategies and for planning the number of customers that should be enrolled in each program. Similarly, a profit-based load management program was introduced in [17] to examine generic direct load control scheduling. Based upon the cost/market-price function, the approach aims to increase the profit of utilities. Instead of determining the amount of energy to be deferred or to be paid back, the algorithm controls the number of groups per customer/load type to maximize the profit.

The direct load control problem of air conditioner loads (ACLs) was addressed using a fuzzy dynamic programming approach developed in [18]. The interrupted capacities of the ACLs and the system load demands are all regarded as fuzzy variables. The scheduling of directly controlled loads and the unit commitment are integrated into the fuzzy dynamic programming structure to reduce the system peak load as well as total operating costs. Genetic algorithm has been applied to scheduling of direct load controls in [19]. The control strategy (or scheduling) arranged by the recursive genetic algorithm not only sheds the load so that the load required to be shed at each sampling interval is individually satisfied, but also minimizes the load shed in order to minimize the utility's revenue loss due to direct load control.

2.2.2 Dynamic Tariff/Pricing

Among some works on interruptible load and tariffs, the need and the role of dynamic pricing options in achieving utility demand management objectives with reference to some of the existing interruptible load management options in different countries were discussed by Shangvi [20].

A consumer behavior model was proposed by David *et al.* [21], [22], incorporating demand elasticity across time, degree of consumer rationality and the supply-side information, and information on the price formation model. The behavior model serves as load management tools as it could help to predict how consumers would respond to the magnitude and variation of electricity price.

Spot pricing of electricity embodies a unified approach to multiple goals of demand-side management by reflecting the time varying nature of the cost of electricity supply. The customer's response to spot prices was discussed in [23], [24]. The attributes that enabled flexible customer response without service curtailments were identified and optimal behavior of industrial customers under spot pricing mechanism was examined in [23]. It also showed that there would be a potential for cost savings associated with spot pricing as compared to those associated with flat rate pricing. An integrated theory of consumer response models and system price forecasting under dynamic conditions created by dynamic pricing was introduced in [24].

Different structures of ILM programs and their effects on system peak demand reduction in the case of Taiwan power system were presented in [2]. Three alternative incentive rates based on avoided-cost were designed for interruptible load programs. Among these, one was actually activated by Taiwan Power Company (Taipower) in 1987, when some preliminary results were obtained.

The design of the optimal interruptible load contract was attempted in [25] by using the mechanism design. It was shown that the so designed contract would give the customers enough incentive to sign up voluntarily for the right contract and reveal their true value of power. The paper suggested that it would not be necessary for a utility to know in advance the type of customer it faced when designing such programs. The paper illustrated and incorporated the importance of load location into the process. Another paper of similar nature [26] attempted to formulate various incentive-responsive demand management programs considering social (utility and customer) optimality, which could help electric utilities to reduce transmission bottlenecks and increase the safety margin of power systems.

It was shown in [27] that the available data on current demand management contracts could be used to calibrate the customer cost function and help design better demand management contracts. It was also shown that the key to have efficient demand management contracts would be by having a good estimate of the customer outage cost function. If the estimated cost function is correct, utilities can optimize the compensation they offer in return for load curtailment.

2.2.3 Callable Forwards

In the context of deregulation, a market for interruptible load (callable forwards), which is continuously tradable until the time of use, was proposed by Gedra and Varaiya [28]. The equivalence between interruptible service contracts and forward contracts bundled with a call option was discussed in detail. In a competitive market, customers wishing to ensure a fixed electricity price while taking advantage of their flexibility to curtail loads can do so by purchasing a forward electricity contract bundled with a financial option that provides a hedge against price risk and reflects the real options available to the customers. This financial instrument was referred to as a double-call option [29]. It was shown that a forward contract bundled with an appropriate double-call option would provide a perfect hedge for customers that could curtail loads in response to high spot prices and could mitigate their curtailment losses when the curtailment decision was made with sufficient lead-time.

2.2.4 Demand-Side Bidding (DSB)

A framework for the incorporation of demand-side participation in a competitive electricity market was introduced by Strabac *et al.* [30]. This framework can be used for comprehensive evaluation of possible scenarios for the implementation of DSB into the electricity market as well as for the assessment of the influence of DSB on total production costs, system marginal price, capacity payment, *etc*.

It was argued in [31] that in a competitive electricity pool, highly flexible forms of generation and load reduction could cause sharp and unwarranted increases in electricity prices if the production schedule would be based on minimization of the total scheduled costs. Such pools are therefore vulnerable to price manipulations by generating companies owning a portfolio of generating units or controlling some demand-side bidding. It was also argued that the competitiveness of demand-side bidding would be artificially inflated if the load recovery periods, which invariably accompany load reductions, were not taken into consideration when establishing the generation schedule.

The behavior of DSB auctions in the power pool framework, using the 24-hour unit commitment model, in which both supply and demand bids are equally treated, was studied in [32]. The customers are allowed to participate in the market by submitting the bid for the reduction in their demand during the system peak periods or during times of contingencies. The market prices are determined at the point where the aggregate supply bids and demand bids intersect. The model also takes into account the load recovery characteristics after the interruption. It was shown that DSB would be able to mitigate the potential for exercise of market power by the supply-side bidders and DSB would help smoothen the system marginal prices and mitigate price volatility.

A method to build optimal bidding strategies for both power suppliers and large customers in a pool-co type electricity market was presented in [33] using a stochastic optimization model. It is assumed in the paper that each supplier/customer bids a linear supply/demand function, and the system is dispatched to maximize the social welfare. Each supplier/customer chooses the coefficients in the linear supply/demand function to maximize benefits, subject to expectations about how rival participants will bid.

2.2.5 Specific ILM Markets

It was suggested by Hirst and Kirby [34] that electric customers, *i.e.*, the load, would participate directly in the wholesale competitive market to improve economic efficiency, increase reliability and reduce environmental impacts of electricity production. It was also suggested that, ultimately, competitive electricity markets would feature two kinds of demand-response programs. First, some customers would choose to face electricity prices that vary from hour to hour. Typically, these prices will be established in the day-ahead markets run by regional transmission organizations. Second, some customers would select fixed prices, as they had in the past, but voluntarily cut demand during periods of very high prices. In the second option, the customer and the electricity supplier would share the savings associated with such load reductions.

In deregulated electricity markets, the ISO has an overall responsibility of providing and procuring various services that are essential for the maintenance of system security and reliability. Such services have been referred to as ancillary services. According to the North America Electricity Reliability Council (NERC) Operating Policy-10 [35], interruptible load management (ILM) is recognized as one of the contingency reserve services. Similarly, the Australian electricity market recognizes "load shedding", both as a frequency control service and a network loading control ancillary service [36]. The Swedish ISO (Svenska Krafnät) also recognizes ILM as an ancillary service, though there is no established financial compensation scheme in place yet. Interruptible load can participate in the reserve markets and it was shown in [5] that it would have the same net effect as reserve generation, that they provide a means of maintaining the balance of supply and demand in the event of a failure in the system. It was shown by Kirby and Hirst [37] that load would be considered as a resource in providing ancillary services. In [38], the design of a market for interruptible loads within the secondary reserve ancillary service was proposed and proved to function well. The locational aspect of interruptible load offers was incorporated in the market operation through marginal loss coefficients at every load bus. The paper also attempted to incorporate the behavior of the interruptible load offers with respect to the information on system operating reserve forecast.

2.2.6 Priority Pricing Mechanism

Priority pricing of interruptible electric service induces each customer to self-select a rationing priority that matches the order of its interruption loss. A tariff structure (with subject to minimization of total expected customers interruption cost) proposed in [39] allowed a customer to choose either early notification and pay a fixed fee, or select no advance notification along with a level of compensation when interrupted. The chosen compensation determines customer service priority and corresponding price.

In the event of shortage in generating capacity, it is obviously inefficient if the electricity utility cuts off customers randomly. It is preferable to set up a market in service priority in which customers who have a greater need pay more for the right not to be cut off. An econometric model of outage costs in Israel was used to calculate the menu of priority rates by season and time of day. Top priority rates range from zero, when the loss-of-load probability (LOLP) is zero, to 8 cents (US) per kWh when the LOLP is highest [40].

2.3 Concluding Remarks

This chapter presents a systematic review on recent research trends in the issues related to interruptible load management. It should be noted that depending on the structure of the electricity market and the perception of the customer, appropriate interruptible load contracts must be designed to attract customer's participation in ILM schemes so as to maximize the overall economic efficiency. It has been shown that ILM would be a cost-saving opportunity for the peak load capacity problem, especially in the deregulated electricity markets.

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CHAPTER 3*

INTERRUPTIBLE LOAD MANAGEMENT: A GLOBAL PICTURE

International experiences on ILM practiced by various electric utilities, electricity markets, independent system operators (ISOs) around the world (i.e., Alberta, England and Wales, California, Australia, New England, New York, New Zealand, Sweden and Taiwan) are presented. The working mechanisms of ILM as implemented by those utilities/markets and their effectiveness in aiding system operation in peak load periods and contingencies are discussed.

3.1 Alberta Power Pool

The Alberta power pool in Canada has a curtailable load program so as to enhance the system security of the Alberta Interconnected Electric System operations. Customers willing to participate in the program need to offer at least 1MW of their load as curtailable load. There is also a requirement for time-of-use metering equipment and the customer's ability to receive dispatch instructions from the pool when required. Customers need to submit their offers in terms of the curtailable MW and the associated price. Based on the offers received by the pool, the pool operator determines the contracted curtailable customers, by classifying them either as Type-1 or Type-2. The details of these two Types are summarized in the Table 3-1.

Table 3-1: Curtailable load program - Alberta [1]

Name	Contract type	Advance notification	Minimum curtailment	Payment structure
Type-1	1-month contract	1 hour	1 MW, up to 4 hours	fixed price per MW per month independent of the number of interruptions requested
Type-2	weekly contract	1 hour	1 MW, up to 4 hours	price per MWh and suppliers are paid only when they are dispatched.

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L.A. Tuan, K. Bhattacharya, "A Review on Interruptible Load Management: Literature and Practice", in Proc. of 33rd North American Power Symposium, Texas, USA, October 15-16, 2001, pp. 406-413.

Offers are ranked in order of their prices, from lowest to highest. The pool operator selects the offers starting from the lowest price till it meets the curtailment quantity requirement.

3.2 Demand Relief Program of California ISO (Cal-ISO)

Cal-ISO has initiated a demand relief program (DRP) in which the customer signs a contract with the ISO for its demand reduction. The ISO implements the program as a means of providing incentives to induce customers to reduce their demand during times of resource shortage. The payments are based on monthly capacity reservation, which is preset by the ISO, and then there are payments for the energy actually disconnected. The customer must be able to reduce at least 1 MW of load demand. The ISO and contracted load enters into the contract. The contracts are different for loads with and without backup generators (BUG). The summary of the contract types is shown in Table 3-2.

Table 3-2: Demand relief program - Cal-ISO [2]

Name	Contract type	Advance notification	Minimum curtailment	When called upon	Payment structure
Without BUG	offer for interruption	call first, 30 minutes	1 MW, up to 4 hours	emergency reserve less than 5%	- monthly capacity reservation payment - payment for energy actually disconnected
With BUG	offer for interruption	call second, 15 minutes	1 MW, up to 4 hours	emergency reserve less than 2%	

According to an evaluation of the DRP in 2000 [3], 269 MW of loads was received and evaluated. The average capacity price for the accepted offers to the DRP was about $36,000 per MW-month. The average energy price was $226 per MWh.

3.3 Demand-side Bidding Mechanism in the UK

Within the trading arrangements of the UK power pool, demand-side bidding was introduced in December 1993 and has since then operated as a demand reduction scheme. In this way, the demand-side bidders are deemed to have a more beneficial effect by reducing demand by a pre-defined amount rather than by an unknown amount. The participants must offer at least 10 MW of their load for curtailment and have a potential for 50 GWh demand reduction over a year. Demand-side bidders are expected to abide by the demand reduction schedules, or if no schedule is received, when the system marginal price is equal or higher than the bid price of the relevant reducible demand.

The payment structure for demand-side bidding is as follows:

- Demand-side bidders pay at Pool Selling Price for all demand actually taken, independent of whether it was offered as being reducible.
- Demand-side bidders receives an Availability Payment, when there is a value, for all demand offered available for reduction, that is not scheduled in the unconstrained schedule.

The intent behind the scheme is to schedule, when cost-efficient, any demand reduction submitted by participants as available for reduction in a similar manner as generating units. The scheme is implemented as follows: The demand-side bidders bid within their fully expected demand for each half-hour of the next day, offer reducible availability, which is the demand available for reduction and the market price above which, the demand will be reduced. The pool operator resolves the market incorporating the demand bids that are scheduled in the unconstrained market settlement in the same manner as scheduling a generating unit. Within one hour of the publication of the system marginal price, the demand-side bidder will receive notification of demand reduction scheduled for the next day. In the event that there is no demand scheduled for reduction, then whenever the value of the marginal price equals or exceeds the bid price, participants are required to reduce demand [4].

3.4 NEMMCO (Australia)

The National Electricity Market Management Company (NEMMCO), which is the ISO in Australia, allows for demand-side bidding in the market. However the rules and codes are not very attractive to the customers. So far, only a few large customers and pump-storage hydro power plants are participating. Customers can register as scheduled loads and can submit their dispatch bids to the NEMMCO. Both generators and customers are centrally dispatched. The dispatch bid can be specified so as to increase or decrease the load if the price is below or above the pre-specified level. The Australian National Electricity Code Administration is taking initiatives to change the rules to introduce more attractive arrangements for demand side bidding [5].

3.5 NE-ISO

New England's demand response programs are aimed at reducing electricity consumption, particularly during periods of high demand when prices are highest. ISO New England's demand response efforts are designed to increase system reliability, mitigate extreme price volatility, and increase the market's response to price signal. Demand response participants are paid monthly capacity payment and energy payment for the demand reduction they offer. ISO New England (ISO-NE) introduced several demand response programs on March 1, 2003. The new programs, that replaced the existing ISO-NE offerings that had been available since 2001, were organized into two categories, as follows [6]:

- Programs that provide reliability, the *Real-Time Demand Response Program* and the *Real-Time Profiled Response Program*, and
- Programs designed to encourage load reduction in response to high real-time wholesale energy prices, which currently includes the *Real-Time Price Response Program*.

Table 3-3 presents a summary of the demand response programs currently available at ISO New England. According to [6], participation in both the price and demand response programs peaked in August of 2003, with 332 and 106 enrolled assets (participants), respectively. Load subscribed in the demand program increased from about 50 MW in March to about 240 MW by summer's start and peaked at 261 MW in July 2003. Price program load enrollments were at their highest in March 2003 with 136 MW, and after a spring-time decline, grew to in excess of 100 MW in July 2003 and reached the summer peak of 130 MW in August 2003.

Table 3-3: NE-ISO Demand Response Programs - Summary

	Reliability Based		Price Based
Program Name	Real time demand response	Real time profile Response	Real time price response
Customer Type	Individual	Group	Individual
Minimum Reduction	100 kW	200 kW	100 kW
Notification	Respond to ISO Control Room request	Respond to ISO Control Room request	Prices are forecasted to Exceed \$0.10/kWh either the night before or during the event day.
Response Time	Within 30-Minutes or 2-Hours of ISO request. Customer must elect option when applying.	Within 2-Hours of ISO Request	Voluntary. Customer decides when and for how long.
Energy Payment Rate and Terms	Greater of Real Time Price or Guaranteed Minimum \$0.50/kWh for 30-Minute Response and \$0.35/kWh for 2-Hour Response.	Greater of Real Time Price Or Guaranteed Minimum \$0.10/kWh	Greater of Real Time Price or Guaranteed Minimum of \$0.10/kWh
Duration of Demand Response Event	Minimum 2-Hour guaranteed interruption	Minimum 2-Hour guaranteed Interruption	Price response “window” open as early as 7:00 AM and remains open until 6:00 PM
Monthly Capacity Payment (\$/kW)	Yes	Yes	No
Metering Requirement	5-Minute Data via internet Based Communication System	Performance determined Through Statistical Analysis	Hourly Data submitted either Daily or Monthly

3.6 New York ISO

There is a provision for customers to offer interruptible load service to a Load Serving Entity (LSE) within the New York ISO (NYISO) and thereby provide additional operating reserve to the latter. They may enter into contracts with LSE for compensation. But in order to participate in the day-ahead or operating reserve market, customers must contract their interruptible load with NYISO directly, thereby allowing direct control, monitoring and billing by the latter. The offers must be larger than 1MW, the response time must be less than 10 minutes and the duration can be up to 1 hour. Interruptible loads are classified into several types:

- *With non-price capped fixed energy:* Load that schedules non-price sensitive energy (*i.e.* a fixed MWh level with no price cap), and then offers to interrupt that load to reduce the demand
- *With price-capped energy:* Load that schedules day-ahead price-sensitive energy, and then offers to interrupt that load to reduce the demand.

There is a provision for 10-minute and 30-minute spinning reserve markets in NYISO wherein interruptible and/or dispatchable load resources located within the NYISO and synchronized to the system can offer to participate. In such cases, they would need to respond to the ISO instructions for load curtailment within 10-minute or 30-minute time-frames, as applicable. The offers in these markets can be for 2 MW or 1 MW of synchronized load at each hour and the NYISO schedules for both 2 MW load and 1 MW 10-minute spinning reserve for each hour. The 2 MW loads are paid for each hour at day-ahead energy price while the 1 MW loads are paid the 10-minute spinning reserve market-clearing price for each hour [7], [8].

3.7 New Zealand - The M-Co

M-co was formed in 1993 as EMCO (the Electricity Market Company) specifically to develop, implement and operate New Zealand's wholesale market for trading electricity. Today, M-co remains at the forefront of positive change within that industry, and continues to increase efficiency and reduce transaction costs for electricity industry participants.

New Zealand Electricity Market (NZEM) was established as a market for both purchasers and generators. However, market participants have identified that more can be done to deliver the purchaser, or demand-side, participation to its fullest potential.

The Demand-side Participation sub-group of the Market Pricing Working Group (MPWG) examined which areas of NZEM could further enhance the accuracy and economic efficiency of the price signal. The group believes this will improve the prospects of demand side participation.

Demand-side bidding is allowed in the market by the market settlement rules. However, only some embedded generators are bidding in the market. Recently the Market Pricing Working Group has proposed some recommendations to promote demand-side bidding [9]:

- Appropriate and timely price signals are a key to demand side participation
- Self-dispatch in response to price signals is the most appropriate means of encouraging efficient demand-side participation
- Demand-side should have greater freedom to self-dispatch in response to a price signal
- Final price should be published as close as possible to real time, as widely as possible
- Lowering fixed fees in NZEM to encourage a higher level of direct demand side membership

3.8 Sweden

Since 1 January 1996, Svenska Kraftnät has been designated as the authority with system responsibility. By law, Svenska Kraftnät has been given the power to issue direct orders to producers to increase and decrease production rapidly in order to keep the balance of the system. Svenska Kraftnät can also issue orders to decrease electricity consumption. It has also been given the right to stipulate the technical requirements and the reliability requirements for production plants and networks.

Svenska Kraftnät is responsible for metering and final settlement at the national grid level. All electricity supply companies have to be connected to the system of metering and final settlement for balancing by Svenska Kraftnät. Svenska Kraftnät has also been designated as the exclusive grid-responsible entity in Sweden according to the Transit Directive [10].

In Sweden, interruptible load management is considered as an important solution for the peak load capacity shortage problem. Swedish ISO (Svenska Kraftnät) as well as other energy authorities are trying to find the optimal mechanism to allow/encourage the customers to participate in the spot market for the change in their electricity demand. The ISO encourages suppliers and customers to reach mutual agreements on how to enable the interruptible load program. The objective is to bring the interruptible load into the market. The ISO recently signed an interruptible load contract with one big industry as part of its ancillary services. As it stands, the spot market in Sweden (Nordpool) is of double-auction type and could well fit in interruptible load offers (or demand-side bidding) [11].

3.9 Taiwan

Taiwan Power Company (Taipower) is a state-owned utility company and provides the electricity in Taiwan. With high load growth and delays in new generation capacity addition due to environmental regulations, the system spinning reserve has been reduced to a low level. Load sheddings had to be implemented when a large unit tripped during the summer peak period and a significant economic loss was incurred [12].

Taipower has successfully implemented an interruptible load control program, as shown in Table 3-4.

Table 3-4: Interruptible load programs - Taipower

Name	Contract type	Advance notification	Minimum curtailment	Payment structure
Strategy A	contract	1 day, 1 week	industrial customers, 5 MW, 6 hours per day	contracted demand is charged with 50% discount price
Strategy B	contract	1 day, 4 hours, 1 hour	all industrial customers, up to 6 hours per interruption, less than 100 hours a year	depending on advance notification time

Note: Strategy A was actually implemented in 1987

The results showed that with the strategy A, customers participated in the program and reduced the system peak load significantly. The system peak was decreased by 2.44% of the total peak demand. The potential effect of ILM with strategy B was also investigated [12]. It showed that there would be a dramatic increase of potential for interruptible load service if the discount rate was increased from 30% to 50%, and more peak load reduction would be exercised if the advance notification time was increased.

3.10 Summary and Concluding Remarks

This chapter presents an overview of how interruptible load management schemes have been working in some of the deregulated electricity markets around the world. A summary of these schemes is presented in Table 3-5.

It can be seen from Table 3-5 that in all the systems discussed, ILM has either been a direct contract with the ISO/load serving entity or direct bidding into the pool market. In the case of New York ISO, the ILM can also participate in the 10-minute spinning reserve market. The advance notification time required varies from 10 minutes to 1 day. The incentive schemes include reduced electricity price; fixed payment per MW per month; and price per MWh of energy actually disconnected.

It should be noted that depending on the structure of the electricity market and the perception of customer, appropriate interruptible load contracts must be designed to attract customer's participation in ILM scheme to maximize the overall economic efficiency. It is realized that in some markets, ILM has been successfully implemented, while in other markets, it is still in development phase. Similar to our conclusions from the previous chapter, the review of utility practices have also shown that ILM would be a cost-saving opportunity for the peak load capacity problem, especially in the deregulated electricity markets.

Table 3-5: Interruptible load programs in selected markets: A summary

Name	Contract type	Advance notification	Minimum curtailment	Payment structure
Alberta				
Type-1	1 month contract	1 hour	1 MW, up to 4 hours	fixed price per MW per month independent of the number of interruptions requested
Type-2	weekly contract	1 hour	1 MW, up to 4 hours	price per MWh and suppliers are paid only when they are dispatched
Cal-ISO				
With BUG		Call second, 15 minutes	1 MW, up to 4 hours	- monthly capacity reservation payment - payment for energy actually delivered
Without BUG		Call first, 30 minutes	1 MW, up to 4 hours	
United Kingdom	bid in pool	1 day	10 MW, 50 GWh per year	- pay pool selling price - paid availability payment
Australia	bid in pool	1 day	large customers	not yet developed
New England	contract	30 minutes or 2 hours	100 kW, 200 kW	- monthly capacity payment - energy payment: greater of real-time price or guarantee minimum prices
New York	contract	10 minute	1 MW and 2 MW, up to 1 hour	1 MW paid 10-minute spinning reserve market price 2 MW paid day-ahead market clearing price
New Zealand	under develop-ment	under development	under development	under development
Sweden	under develop-ment	under development	under development	under development
Taiwan				
Strategy A	contract	1 day, 1 week	5 MW, 6 hours per day	contracted demand is charged with 50% discount price
Strategy B	contract	1 day, 4 hours, 1 hours	all industrial customers, up to 6 hours per interruption	depending on advance notification time

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CHAPTER 4*

THE DESIGN OF INTERRUPTIBLE LOAD SERVICE MARKETS

This chapter deals with optimal procurement of interruptible load services within secondary reserve ancillary service markets in deregulated power systems. The proposed model is based on an optimal power flow framework and can aid the Independent System Operator (ISO) in real-time selection of interruptible load offers. The structure of the market is also proposed for implementation. Various issues associated with procurement of interruptible load such as advance notification, locational aspect of load, power factor of the loads, are explicitly considered. It is shown that interruptible load market can help the ISO maintain operating reserves during peak load periods. Econometric analysis reveals that a close relationship exits between the reserve level and amount of interruptible load service invoked. It was also found that at certain buses, market power exists with the loads, and that could lead to unwanted inefficiencies in the market. Investing in generation capacity at such buses can mitigate this. The CIGRE 32-bus system appropriately modified to include various customer characteristics is used for the study.

4.1 Introduction

As described in Chapter 3, in deregulated electricity markets, the ISO has the overall responsibility of providing and procuring various services that are essential for the maintenance of system security and reliability. Such services are referred to as *ancillary services*. According to the North America Electricity Reliability Council (NERC) Operating Policy-10 [1], interruptible load management (ILM) is recognized as one of the contingency reserve services. Similarly, the Australian electricity market recognizes "load shedding", both as a frequency control service and a network loading control ancillary service [2]. The Swedish ISO (Svenska

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* The work contained in this chapter has been published in the following papers:

L.A. Tuan, K. Bhattacharya, "Interruptible Load Management Within Secondary Reserve Ancillary Service Market", in Proc. of IEEE Porto PowerTech'2001 Conference, Vol. 1, Porto, Portugal, September 10-13, 2001.

L.A. Tuan, K. Bhattacharya, "Competitive Framework for Procurement of Interruptible Load Services", *IEEE Transactions on Power Systems*, Vol. 18, No. 2, May 2003, pp. 889-897.

Krafnät) also recognizes ILM as an ancillary service and is in the process of establishing a proper framework for its functioning.

We have also seen from our reviews in Chapters 2 and 3 that it has been generally accepted that ILM has an important role to play as system ancillary services, particularly as contingency reserve services. It is more so, since the operating margins available to the ISO have been reducing drastically with increasing market competition.

Contrary to pool markets, where generation sell offers and customers buy bids are treated simultaneously within the scheduling program by the pool operator, bilateral contract dominated markets have a different scenario. In bilateral contract dominated markets, the ISO has no say over generation scheduling or unit commitment decisions (for example, Sweden). The generating companies can enter into direct contracts with customers that can be days, weeks, or even months in advance. The ISO is only informed about these transactions to take place on a given day and hour. It is the responsibility of the ISO to meet these transactions while satisfying system constraints. In such markets, interruptible load options are therefore required to be handled by the ISO independently as an ancillary service.

In this chapter, we developed a framework for a competitive market for interruptible load services. Customers participating in this market shall submit to the ISO their offers for load reduction (in MW) along with the desired price for such a service (in $/MWh). The ISO settles the market and determine the optimal set of contracts and the uniform market price. The attractiveness of this market is that, although it is independent of the real power market, it responds to price and demand fluctuations in the real power market.

The work is an extension of [3], wherein optimal interruptible tariffs were worked out for a vertically integrated electric utility. The optimal incentives were determined based on maximization of the utility's social welfare. The present work, on the other hand, introduces a competitive framework and proposes a uniform price based market settlement model using participant bids. It also incorporates market imperfection arising from system conditions dependent participants' bidding strategies.

4.2 Design of Interruptible Load Markets

4.2.1 Market Structure

Ideally, the ISO's objective while formulating the optimal contracts would be to seek those customers offering the lowest price. However, such a selection, without taking into account the system and load flow pattern, may give rise to transmission congestion, increased system losses, increased reactive support requirements, *etc*. This may happen, since, choosing to interrupt a low-priced offer load located at a remote area may increase the system power flows in an undesirable manner. Thus, a location-dependent parameter to re-value the customer price offers is introduced. Using the re-valued offer prices, the ISO obtains the optimal interruptible load contracts while satisfying all system constraints.

An OPF based framework has been used to model the above features of the interruptible load market, customers offers, locational aspects in their offers and the final optimal contracting decisions of the ISO. The OPF model is suitably modified to incorporate the above aspects, while also satisfying the usual system constraints such as bus voltage limits, reactive power support limits, *etc*.

A schematic diagram of the proposed interruptible load market structure operated by the ISO is shown in Figure 4-1. The time frame of market operation is also shown in the figure. The ISO who is responsible for operation of the interruptible load market shall call for offers for load interruption on an hour-to-hour basis. The participants submit their offers to the ISO for hour k at hour k-1. The ISO has also received, in advance, information on unit commitment schedules from independent generators. Based on these, it evaluates the offers and determines the optimal selection of interruptible loads as per its requirement and that is when the interruptible load market is cleared. The selected interruptible loads can expect to be called upon, when necessary, during the next hour (*i.e.*, between hour k and hour $k+1$). The market participants submit their offers specifying the price β (in \$/MWh) for energy to be interrupted and the quantity of interruptible load μ (in MW).

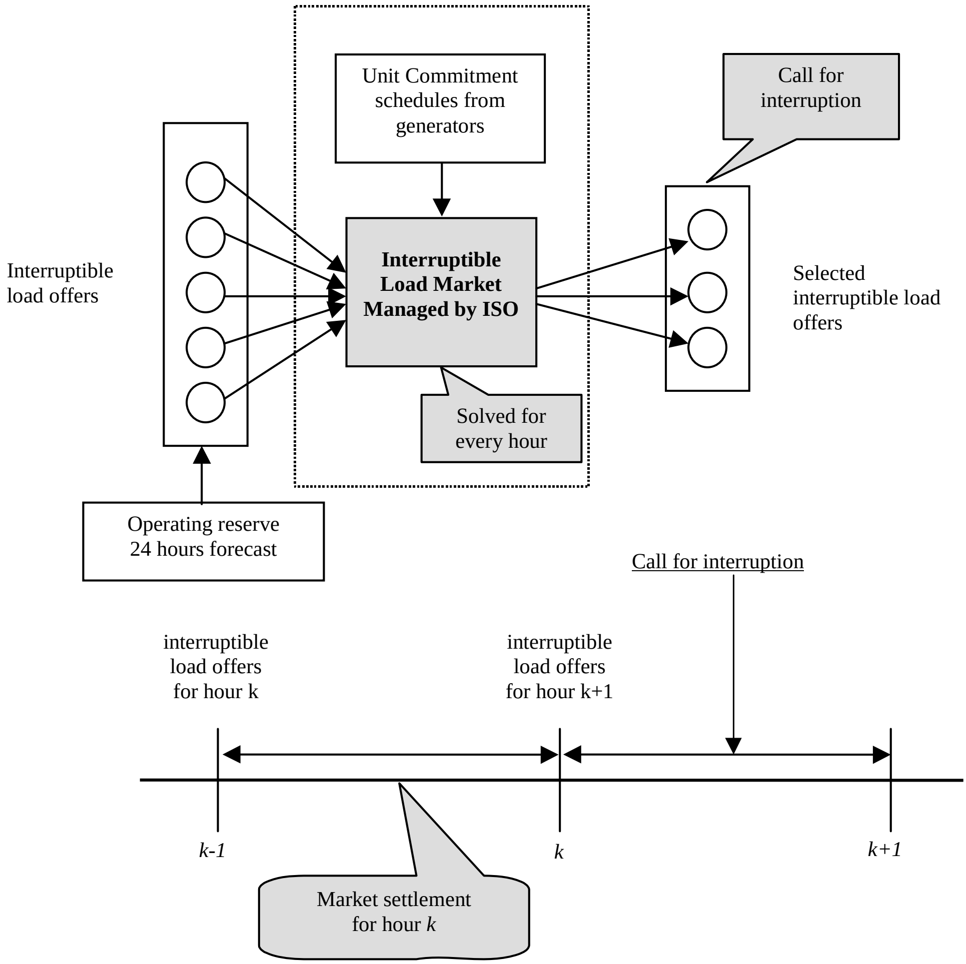

Figure 4-1: Schematic representation of the proposed interruptible load market operation

4.2.2 Optimum Procurement of Interruptible Load Services

Procurement of interruptible load services needs to be carried out by the ISO while addressing the following issues:

- The secondary reserve service cost (SRC), defined as the total payment to interruptible load customers less the benefits accrued to the system from load interruption, is minimized.

- It is not desirable to increase the ISO's burden on procurement of other services such as loss compensation or reactive power services through increased losses. Thus, procurement of interruptible load services should seek to minimize system losses.
- Mandatory requirement of maintaining the specified amount of system contingency reserve is satisfied.
- All operating constraints of the system are satisfied.

The procurement scheme proposed in this chapter works in two steps, the first step evaluates the *worth* of an interruptible load in terms of its location in the system, and in the second step, the information from the first is incorporated to obtain the optimal decision:

- *Step-I, (Base-OPF)*: Obtain OPF solution by minimizing total system losses, and hence determine the marginal loss coefficients λ_i at each bus *i*. The value of λ (p.u.MW/p.u.MW) denotes the change in system loss due to a unit change in load at a bus. This parameter is used to re-value the price offers and also to evaluate the benefit accrued, in terms of total loss reduction due to load interruption.
- *Step-II, (IL-OPF)*: A modified version of Base-OPF is used that includes the interruptible load offers. The objective is to minimize the SRC. The λ's calculated from Base-OPF are used to formulate SRC. The market is settled on *first price uniform auction*, which means, all selected providers receive a uniform price, that is the highest priced offer accepted in the auction. As discussed in [4] and [5], this provides the players enough incentives to offer their true costs. IL-OPF determines the uniform price ρ ($/MWh) to be paid to selected interruptible load contracts and the amount of load to be interrupted for each selected offer during the next hour.

A. Base-OPF Model:

Objective Function: The objective is minimization of total system loss (L, p.u. MW) during an hour, given by:

$$L = 0.5\sum_i \sum_j G_{i,j}\left(V_i^2 + V_j^2 - 2V_iV_j\cos(\delta_j - \delta_i)\right) \tag{1}$$

V_i is the voltage at bus *i*, δ_i is the corresponding voltage angle and $G_{i,j}$ is the conductance of line *i-j*, p.u.

Load Flow Equations: These are modified to include the load interruption ΔPD as requested by the ISO from the interruptible load participants.

$$PG_{i,m} + PG_{i,b} - PD_{i,m} - PD_{i,b} + \sum_{Type} \Delta PD_{i,Type} = \sum_{j,\ j \neq slack} |V_i||V_j|Y_{ij} \cos(\theta_{ij} + \delta_j - \delta_i) \tag{2}$$

$$QG_{i,m} + QG_{i,b} - QD_{i,m} - QD_{i,b} + \sum_{Type} \Delta QD_{i,Type} + QC_i = - \sum_{\mathrm{j},\ j \neq slack} |V_i||V_j|Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) \tag{3}$$

$$\Delta QD_{i,Type} = \tan(\cos^{-1}(PF_{Type}))\Delta PD_{i,Type} \tag{4}$$

ΔQD in (4) represents the reactive power relief associated with real power interruption ΔPD and will depend on load power factor PF. *Type* is an index used with loads, to distinguish between different customer categories. This categorization has been made using different PFs for different customer *Type*. Y_{ij} is an element of the network admittance matrix, while θ_{ij} is the angle associated with Y_{ij}.

In (2), (3) and (4), PG and PD are generation and load at a bus *i* or *j* while QG and QD are corresponding reactive power generation and demand respectively. It may be noted that generation and demand is accounted for by two different sources and sinks respectively. For example, we assume a generator ‘i’ is producing an amount $PG_{i,b}$ to meets its bilateral contracts and an amount $PG_{i,m}$ to sell in the spot market. Similarly, load at bus ‘i’ comprises a part $PD_{i,b}$ that is through bilateral contracts and a part $PD_{i,m}$ that is purchased in the spot-market. Such representation of the generation and load balance is typical of the Swedish/Nordic system which is dominated by bilateral contracts, while also having a participation in the spot market. The bilateral contracts have been modeled using the principle of “column rule” and “row rule” and have been explained in detail in Appendix 1.

Upper and Lower Limits on Buses Voltages:

$$\begin{aligned} &\left|V_i\right| = \text{constant}, \quad \forall i = 1,\ldots, NG \\ &V_i^{\min} \le \left|V_i\right| \le V_i^{\max}, \quad \forall i = 1,\ldots, NL \end{aligned} \tag{5}$$

V^{max} and V^{min} are the upper and lower limits on bus voltages.

Upper and Lower Limits on Reactive Power Supports:

$$QC_i^{\min} \le \left|QC_i\right| \le QC_i^{\max}, \quad \forall i = 1,\ldots, NL \tag{6}$$

QC is the reactive power compensation required at a bus to maintain voltages within specified limits while QC^{max} and QC^{min} are the upper and lower limits respectively, of reactive power compensation available at a bus.

The Base-OPF model as described above is a nonlinear programming problem and is solved using the well-known GAMS/MINOS solver [6].

B. *IL-OPF Model*

Objective Function: The objective is to minimize the secondary reserve service cost for each hour:

$$SRC = \sum_i \sum_{Type} \left(\rho \cdot \Delta PD_{i,Type} - CL \cdot \lambda_i \cdot \Delta PD_{i,Type}\right) \tag{7}$$

CL denotes the cost of loss (\$/MWh) and when multiplied with λ_i and $\Delta PD_{i,Type}$ denotes the ISO's benefit from demand reduction at a bus. Evidently, the gross economic value of loss reduction from load curtailment depends on location of load reduction, given by λ_i. The first component in (7) denotes the total payment made to interruptible load customers selected for interruption. Note that ρ is the uniform interruptible load price that is determined from the IL-OPF model and is payable to all selected interruptible load offers invoked.

Operating Reserve Constraints: This constraint ensures that a pre-specified and mandatory level of operating reserve is maintained at all time. In this paper we consider operating reserve to be the *generation reserve* and is obtained from total committed capacity net of generation.

$$\sum_i^{NG} PG_i^{\max} \cdot UC_i - \sum_i^{NL} PD_i + \sum_i^{NIL} \sum_{Type} \Delta PD_{i,Type} \ge RES \tag{8}$$

RES denotes the reserve margin requirement for the entire system.

Limit on Interruption: The actual interruption invoked by the ISO is constrained by the quantity offered by customers for interruption:

$$\Delta PD_{i,Type} \leq \mu_{i,Type} \cdot U_{i,Type} \qquad \forall i = 1,\ldots, NIL \tag{9}$$

Further, the quantity offered by an interruptible load market participant is limited by the total demand at its disposal:

$$\mu_{i,Type} \leq a_0 \cdot PDem_{i,Type} \qquad \forall i = 1,\ldots, NIL \tag{10}$$

U is a binary decision variable denoting the selection (U=1) or otherwise (U=0) of interruptible load offers. NIL is the set of buses with customers participating in the interruptible load market. PDem is the real power demand by customer *Type*. a_0 is a scalar, $0<a_0<1$, determining how much of the demand can be made available for curtailment by a participant without causing any economic loss to itself.

Market Settlement: The interruptible load market is settled on first price uniform auction, where all selected offers are paid the same price ρ (interruptible load market price), which is the highest accepted offer price. The interruptible load market price is determined from IL-OPF using the following inequality constraint:

$$\rho \geq U_{i,Type} \cdot \beta_{i,Type} \qquad \forall i = 1,\ldots, NIL \tag{11}$$

Other constraints: Other constraints in the model remain the same as those in Base-OPF:

- Load flow equations (2), (3) and (4)
- Limits on bus voltages and reactive power support (5) and (6)

The IL-OPF model, as described above, is a mixed integer nonlinear programming problem and is solved using the well-known GAMS/DICOPT solver [6].

4.3 Simulations And Discussions

4.3.1 System Descriptions

The CIGRE-32 bus system, which approximately represents the Swedish grid, has been used for the simulation studies [7]. The system configuration as well as other associated information is provided in Appendix 2.

Certain modifications from the given system are incorporated in this work with regard to the load representation. The hourly load variation at a bus is accounted for by applying a load scaling factor (LSF) at each hour. The load at each hour *k* will thus be calculated as follows:

$$PD_i^k = PD_i \cdot LSF^k \tag{12}$$

All buses are classified into three *Types,* industry (*ind)*, commercial (*com)* and agriculture (*agr)*. Further, at each load bus, the load share (LS) of a particular type of customer is allocated using a uniform random number generator. Using LS values, customer-type demand at a bus is determined by:

$$PDem_{i,Type} = PD_i \cdot LS_{i,Type} \tag{13}$$

The load PF of customer types are assumed as follows:

$PF_{Ind} = 0.95$; $PF_{Com} = 0.7$; $PF_{Agr} = 0.8$

4.3.2 Simulation Studies

The procurement scheme described in Section 4.2.2 is used to carry out case studies to examine the operation of the interruptible load market and its role in aiding system operation during contingencies. The simulation cases constructed for analysis include:

- *Case 1:* Base-case market for interruptible load
- *Case 2:* Base-case market for interruptible load with loss of a large generator (1000 MW) during peak hours (17.00 – 21.00)
- *Case 3:* Real power market demand increases sharply during 17.00–21.00 hours

Since the interruptible load market is proposed to function as an hour-ahead market, the participants can be expected to have information on next hour demand (and hence system reserve) forecast, transmission capacity limits across the borders and outage conditions in the system, if any, made available by the ISO. It is natural that interruptible load offer prices will be sensitive to operating reserve availability during the next hour.

Figure 4-2 shows a typically expected as well as a simplified trend of offer price as a function of the operating reserve. Figure 4-2 (a) depicts the likely bidding behavior of interruptible load participants in response to the level of system reserve. The ISO can be expected to be aware of such behavior from the market participants and incorporate that in its market settlement model in order to arrive at a realistic decision on selection of interruptible loads. Thus, the details of Figure 4-2 are being handled by the ISO. However, since determining the exact function for such behavior is very difficult, for the sake of simplicity, we use a linear function (Figure 4-2 (b)). Further, we also incorporate an upper limit on operating reserves, RLIM, above which interruptible load will not be required by the ISO. This allows the interruptible load market to address critical system conditions only.

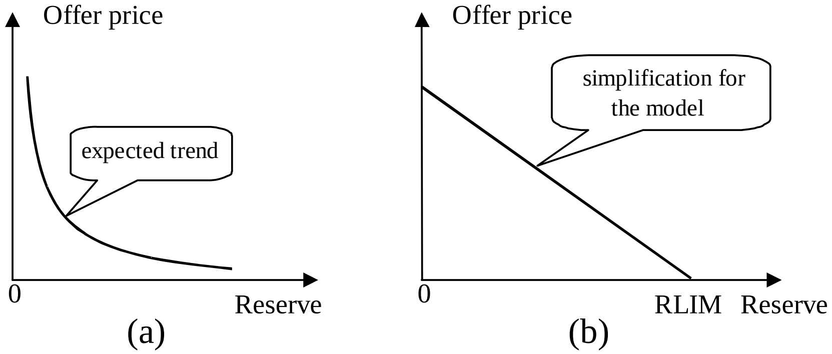

Figure 4-2: Expected and simplified bidding behaviors of interruptible load market participants

From Figure 4-2 (b), the offer price β can be given as:

$$\begin{aligned} &\beta_i = \beta o_i\,(1 - RES / RLIM) \quad \forall i = 1,\ldots,NIL, \text{ when } RES \le RLIM \\ &\beta_i = 0 \;\; \forall i = 1,\ldots,NIL, \text{ when } RES \ge RLIM \text{ (no interruption)} \end{aligned} \tag{14}$$

As mentioned in (8), RES denotes the reserve margin requirement for the entire system while RLIM is the reserve limit above which interruptible load market is not operated.

Figure 4-3 shows the nominal load curve of the system and how the load curve is modified after the base-case market for interruptible load is activated. It is seen from Figure 4-3 that the peak load occurs during hours 11-13 and 18-20. The base-case market works particularly effectively during the evening hours (18-20) and helps flatten the peak to a certain extent. The total load interruption called for, during hour 19 is about 6.4% of the total demand at that hour. It is also seen that the interruptible load market price (*shown on the secondary y-axis*) corresponds to activation of the load interruptions.

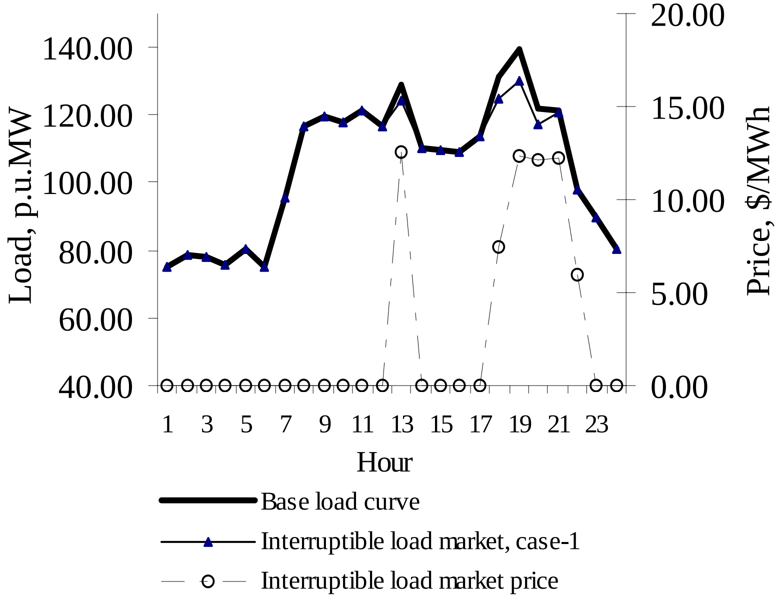

Figure 4-3: Operation of the base-case interruptible load market (Case 1)

As described earlier, for Case-2, we consider the loss of one large generator occurring during hours 17.00-21.00 when the base-case market is operating. Understandably, more interruptible loads are contracted and invoked in this case (13.6% of the total peak demand) by the ISO in order to maintain the system conditions within allowable limits (Figure 4-4).

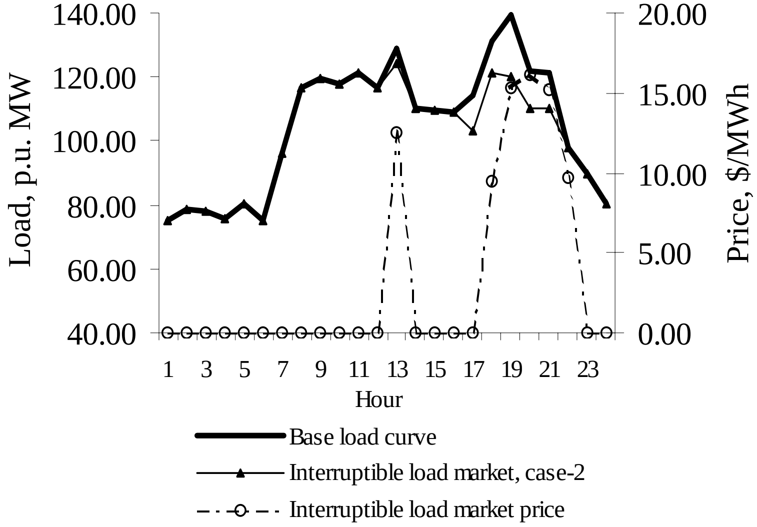

Figure 4-4: Operation of the interruptible load market with one large generator on outage

The market price for interruptible load is now significantly higher during the hours when load curtailments are required. This shows a direct dependence of the interruptible load market price on prevalent system conditions, in particular, on available system reserves.

Case-3 scenario, where the demand in spot-market increases sharply, shows that the interruptible load providers help to reduce the system demand (Figure 4-5) and keeps the system in balance.

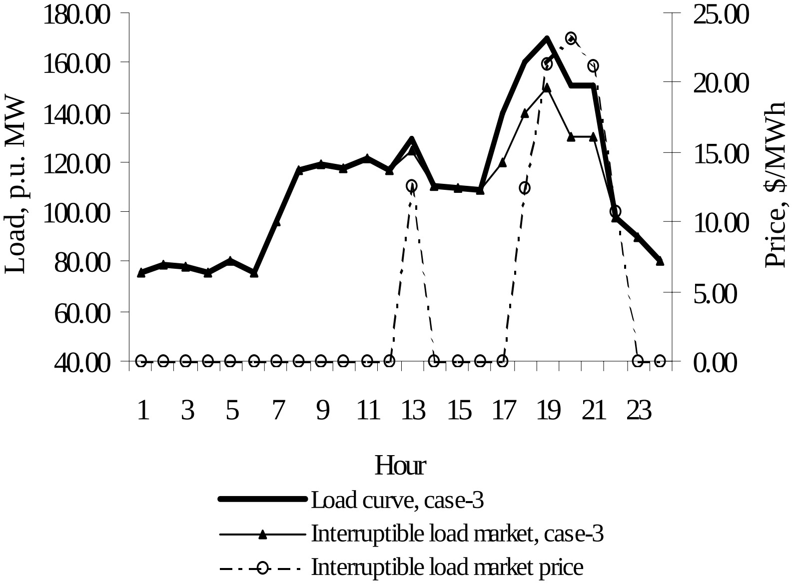

Figure 4-5: Operation of interruptible load market
with spot-market demand spikes

However, the ISO has to pay a very high price to these providers since the interruptible load offer prices tend to be high in this case. From Figure 4-5, we can also note that the interruptible load market price is highly elastic to the system demand.

Table 4-1 shows the total interruption and total payment by the ISO during a day for different cases. For the most severe contingency case (case 3), the ISO has to pay the maximum in order to compensate for the shortfall in available generation.

Table 4-1: Total Interruption and Payment

	Payment, US$	Total interruption, MWh
Case 1	28,925	3,208
Case 2	82,181	6,906
Case 3	165,648	10,603

4.3.3 Relationship Between Reserve and Actual Interruption

In order to investigate the relationship between the actual interruption invoked by the ISO vis-à-vis the reserve available, we employed an econometric technique, the method of ordinary least squares (OLS). The details of this method is presented in the Appendix 3. In this method, the amount of real power interruption called for by the ISO is regressed over the reserve level of the system over 24 hours of a day. In order to have a large sample set of interruptible loads, the real power demand was increased 1.5 times as compared to those reported in Section 4.3.2. As can be seen in Figure 4-6, there is a fairly strong correlation between load interruption and reserves.

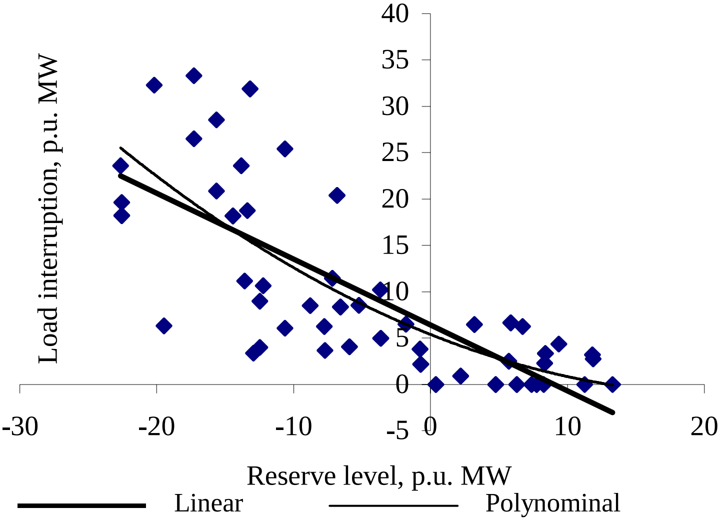

Figure 4-6: Load interruption versus system reserve

The econometric exercise also indicates that the reserve level is a *highly significant* variable in predicting the load interruption. Table 4-2 gives the estimated coefficients for a combined relationship for all hours and all scenarios considered together. In Table 4-2, N is the number of observations, *x*-variable is the reserve level of the system. *t-statistics* indicates the level of significance of the estimated coefficients. Any value of *t*-statistics greater than 2.6, in absolute terms, reflects that the coefficient is significant at 1% [8]. R^2 indicates how closely the estimated model fits with the observed data. From the obtained values of R^2 in Table 4-2, we see that the system reserve level explains up to 57%, the load curtailment decisions of the ISO considering a linear model, while up to 59%

when a second-order polynomial model is used. The estimated linear and second-order polynomial models are given by (15) and (16), respectively:

$$\Delta PD = -0.711 \cdot (RES) + 6.4131 \tag{15}$$

$$\Delta PD = 0.013 \cdot \left(RES\right)^2 - 0.587 \cdot \left(RES\right) + 5.383 \tag{16}$$

Table 4-2: Econometric Estimates of Load Interruption as Functions of Reserve

	Intercept (t-statistics)	x-variable (t-statistics)	x^2-variable	R^2	N
Linear	6.4131*** (8.08)	-0.7109*** (-9.59)	-	0.57	72
Polynomial	5.38*** (5.49)	-0.587*** (-5.76)	0.013 (1.736)	0.59	72

*** Denotes significance at 1%

4.3.4 Market Power in Interruptible Load Markets

Interruptible load services, provided through a competitive market can sometimes provide strategic advantages to certain loads by virtue of their location in the system. In this sub-section we attempt to examine if such strategic advantages do exist at any load bus in the system, whether certain loads have market power, *i.e.*, *do they manage to remain the price setter under all circumstances?* If such situations exist, how do we identify those loads? This information can help the ISO to handle the interruptible load market more efficiently.

In order to address these issues, we examine for every hour, which buses retain the power to set the market price. Five scenarios (S1 to S5) are constructed with the assumption that load at all buses indulge in gaming simultaneously by increasing their offer prices by 10%, 20%, 30%, 40%, and 50%, respectively.

In Table 4-3, we list the price-setter bus for each hour and for all five scenarios as well as for the base case. The following observations can be made from the table:

- No interruption is called for at hours 2, 4, 7, and 22 in any of the scenarios, hence there are no price-setter buses for these hours.

- In the base case scenario, there are eight buses (1022, 1041, 1042, 1043, 1044, 1045, and 4072) which account for the price-setting of the remaining 20 hours. Of these, bus 1041 accounts for price setting in 6 hours (11, 15, 17, 18, 19, and 23) and 4072 in 4 hours (8, 14, 21, and 24).
- Considering the gaming scenarios, we see that bus 1044, which is the price-setter for hours 1, 9, and 12 in the base case, has the market power during hours 9, 12, and 20.
- Buses 1042, 4071, and 4072 do not hold any market power. If theses buses indulge in gaming, these do not remain as price-setters any longer.
- Bus 1045, which was the price-setter for hour 6 only in the base case, can hold a very high market power if it indulges in gaming. As we see across scenarios, it can hold price setting power for hours 5, 6, 14, 18, and 21.
- Buses 1022 and 1043 hold market power at hours 8 and 17, respectively.
- Bus 1041, which in the base case is the price-setter for 6 hours during afternoon and evening peak periods, retains considerable market power if it indulges in gaming. As seen from scenarios, it holds market power in hours 10, 11, 13, 15, and 16.

Table 4-3: Price-Setter Buses for Each Hour in Different Gaming Scenarios

Hour	Base Case Scenario	S1 (+10%)	S2 (+20%)	S3 (+30%)	S4 (+40%)	S5 (+50%)
1	1044	1042	1012	1012	1012	1012
3	1042	4071	4071	1042	1045	1045
5	1042	1042	1045	1045	1045	1045
6	1045	1045	1045	1045	1022	2031
8	4072	1022	1022	1022	1022	1011
9	1044	1044	1044	1044	1044	2032
10	1022	1041	1041	1041	1041	1041
11	1041	1041	1041	1041	1041	1022
12	1044	1044	1044	1044	1041	1012
13	1022	1013	1041	1041	1041	1041
14	4072	4072	4072	1045	1045	1045
15	1041	1041	1041	1041	1041	1041
16	1043	1041	1041	1041	1041	1012
17	1041	1043	1043	1043	1043	1011
18	1041	1045	1045	1045	1045	1045
19	1041	1044	1022	1022	1043	1043
20	4071	2031	1044	1044	1044	1044
21	4072	4072	1045	1045	1045	1045
23	1041	1011	1011	1011	1011	1011
24	4072	4072	4072	1013	1042	4072

Table 4-4 summarizes the load buses which hold the market power (*i.e.*, remain as the price-setter) in different hours in a day across different scenarios.

Table 4-4: Buses with Market Power During Hours in A Day

Buses	Hours
1012	1
1045	5,6,14, 18,21
1022	8
1044	9,12,20
1041	10,11,13,15,16
1043	17
1011	23

4.4 Conclusions

In this chapter, the design of a market for interruptible load services within the secondary reserve ancillary service market has been proposed. The location aspect of interruptible load offers has been incorporated in the market framework through marginal loss coefficients at every load bus. The paper also attempts to incorporate the behavior of interruptible load offers with respect to the information on system operating reserve forecast. The case studies show that the interruptible load market helps to reduce the system demand during the peak hours and in cases of contingencies. The market price is highly sensitive to the system operating conditions and demand. Econometric analysis shows the existence of a close relationship between the reserve level and actual load interruption. It was also found that at some buses, the loads may have the capability to retain market power through gaming on their offer prices. This needs to be mitigated by the system operator through investments in generation capacity at such buses. With a proper contracting and market settlement framework, as proposed in this paper, the interruptible load market would be an effective option as an ancillary service for the system operator to choose amongst its available services.

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CHAPTER 5*

TRANSMISSION CONGESTION MANAGEMENT IN DEREGULATED ELECTRICITY MARKETS: A REVIEW

This chapter provides a comprehensive review of utility practices as well as research methods in the area of transmission congestion management in deregulated electricity markets. The classification of congestion management methods has been made according to security-constrained generation re-dispatch, zonal/cluster-based management, network-sensitivity-factor-based method, congestion management using FACTS devices, congestion pricing and market-based methods, congestion management using demand-side resource. The other important part of this paper is the discussion on international practices in congestion management at various electricity markets around the world- California, New York, New England, PJM, ERCOT, Nordic and the Spanish power market. The working mechanisms for congestion management by these utilities are discussed. It can be seen in the paper that many electricity markets are utilizing the methods which are widely addressed in the literature of the power engineering community. However, the methods used are widely different from one another as a result of different congestion management objectives in various electricity markets.

5.1 Introduction

An important aspect of the efficient operation of competitive electricity markets is judicious integration of the fundamentals of market economics with physical characteristics of operating the power system. Among the most critical issues in operating the system are managing transmission congestion and scheduling ancillary services. Transmission congestion occurs whenever the state of the power grid is characterized by one or more violations of the physical, operational, or policy constraints under which the grid operates in the normal state or under any credible contingency [1]-[3].

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* The work contained in this chapter has been published in the following papers:

L.A. Tuan, K. Bhattacharya and J. Daalder, “Review of Congestion Management Methods in Deregulated Power Market”, in Proc. of 7th IASTED International Conference on Power and Energy Systems (PES 2004), Florida, USA, November 28 - December 1, 2004.

L.A. Tuan and K. Bhattacharya and J. Daalder, “Congestion Management Strategies in Deregulated Power Market: A Theoretical Review and Reflections in Practice”, *IEEE Transactions on Power Systems* (in review)

Physical upgrades to the existing transmission capacities are not the only solution to the congestion problem. Market-based mechanisms, offering a more efficient utilisation of the capacity, often offer a viable alternative. In the erstwhile vertically integrated utilities, the system operator sought to maximize the social welfare with distributional equity (meeting the load at all times) as the main criteria, for the system as a whole. The operating paradigm was based on achieving the system solution while meeting reliability and security margins. In this operating paradigm, the system operator knows the marginal cost of production of each generating unit and an Optimal Power Flow (OPF) tool is used to re-dispatch these units to avoid transmission congestion in a least-cost manner. Since the nineties decade, many electric utilities world-wide have been forced to change their ways of doing business, from vertically integrated functioning to open-market systems. The reasons have been many, and differed, across regions and countries. Reforms were undertaken by introducing commercial incentives in generation, transmission and distribution of electricity, with in many cases, large efficiency gains. Though this may seem fairly straight-forward at first glance, there are several complexities involved in restructuring and several new issues have surfaced. Some of them have been solved while others are being debated at various levels. One of those new issues is congestion management. Congestion management has become more important and difficult in the emerging deregulated electricity markets due to the increased number and magnitude of power transactions as well as due to the obvious fact that congestions in the transmission system will create problems to the delivery of power transactions, increase market price and market power [4]-[6].

The objectives of congestion management would now be i) to develop MW schedules which minimizes the system cost variation of the initial market clearing while fulfilling system security criteria; ii) to provide appropriate economic signals that are consistent with the MW schedules; iii) to facilitate the management of transmission congestion risks. Congestion management is also done with respect to maximizing the overall satisfaction degree of all participants in the market [7]-[9]. Three broad methods of congestion management are currently in use around the world. One method is basically a centralized optimization exercise, either explicitly with some form of *generation re-dispatch* with security and transmission constraints, or implicitly, direct control of system operators control congestion [10]. A second method is based on the use of price signals derived from *ex ante* market resolution to deter congestion by allowing congestion to constrain scheduled generator output prior to real time operation. Inevitably some congestion may still arise and must be corrected in real time by centralized control [11]. A third method seeks to control congestion by allowing or disallowing bilateral transmission, agreements between a producer and a consumer, based on the effect of the transaction on the transmission system [1].

The objective of this chapter is to provide a comprehensive review on existing congestion management methods that are available in the technical literature being put forward in the course of deregulation.

5.2 Congestion Management Methods Reported in Literature

Several methods have been reported that address the congestion management problem in deregulated electricity markets. These can be classified into broad groups, as follows (Figure 5-1):

- *security-constrained generation re-dispatch*
- *zonal / cluster-based management*
- *network sensitivity factor based method*
- *using demand response ancillary services*
- *using financial transmission rights (FTRs)*
- *congestion pricing and market based methods, using demand side resource*
- *using FACTS devices*
- *congestion pricing and market-based methods*
- *and some other methods.*

Solutions techniques for these congestion management methods also belong to the publication classification map.

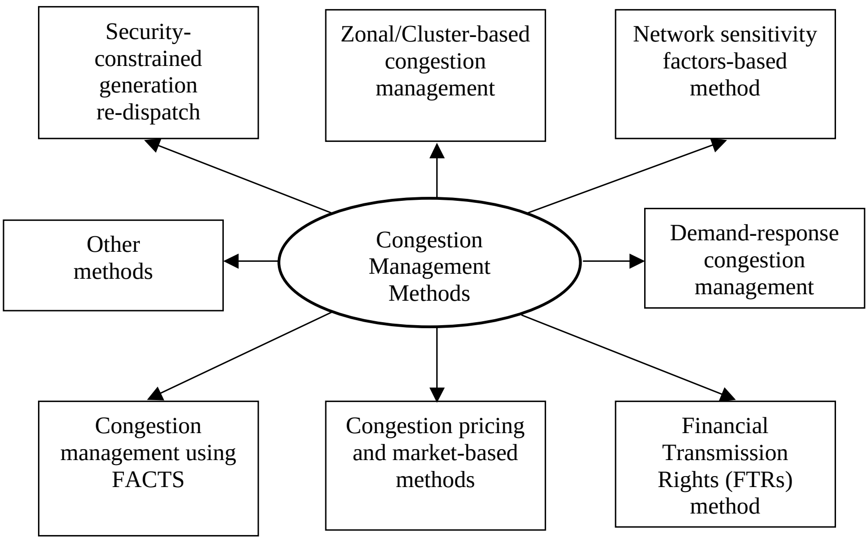

Figure 5-1: Categorization of congestion management methods

5.2.1 Security-Constrained Generation Re-dispatch

One of the most common approaches to alleviate congestion in the network is to re-schedule of the generation by the optimal power flow model with transmission constraints as well as bus-voltage constraints to maintain the system security. An unified framework for the representation of market dispatch and re-dispatch problems that the independent grid operator must solve in congestion management in various jurisdictions was developed in [2]. This framework is used to compare the performance of different congestion management approaches that exist today in various markets in the world. An optimization procedure for re-dispatch of generation is proposed in [12] in order to alleviate transmission congestion on the network. Consequently, a new approach to allocate the cost of congestion and losses to the nodes of the transmission network based on node's responsibility is proposed. While a minimum-distance generation re-dispatch was suggested in [13], where the economic value of the transaction adjustment is dis-regarded.

While solving the congestion problem with generation re-dispatch, Huang and Yan [14] investigates the impacts of thyristor controlled series capacitor (TCSC) and static VAr compensator (SVC) with the objective of minimizing the total amount of transactions being curtailed on this re-dispatch method. This paper suggested that the improvement of total transfer capability (TTC) by using TCSC and SVC with the consideration of transaction patterns would reduce the possibility of congestion occurrence. An optimization method to analyze and solve the transmission overloads that arise in each hourly scenario of the Spanish power system, after the electricity market has been cleared, was proposed in [15]. Congestions in the Spanish electricity market could be removed by increasing and decreasing generation of connected units, and by connecting off-line ones.

Yamin and Shahidehpour [16] proposes a generalized active/reactive iterative coordination process between generation companies (GENCOs) and the Independent System Operator (ISO) for active (transmission congestion) and reactive (voltage profile) management in the day-ahead market. GENCOs apply priced-based unit commitment without transmission and voltage security constraints, schedule their units and submit their initial bids to the ISO. The ISO executes congestion and voltage profile management for eliminating transmission and voltage profile violations. If violations are not eliminated, the ISO minimizes the transmission and voltage profile violations and sends a signal via the Internet to GENCOs. GENCOs reschedule their units taking into account the ISO signals and submit modified bids to the ISO.

A combination of load curtailment and generation redispatch was used for congestion management procedure as suggested in [17]. A set of indices is introduced to measure the effectiveness, extent of load curtailment, and economic impact. The procedure can select the most effective load curtailment option, which is agreeable to the customer affected and economically desirable. Matching generation redispatch procedures have been tested with minimal adjustment cost optimization and bilateral transaction approaches. This procedure is simple to implement, and transparent to transmission users and would encourage elastic use of electricity in congested conditions, and also to discourage market manipulation by local suppliers.

The generation ramping constraints was incorporated into congestion management in [18]. The paper presents the congestion management formulation with ramping constraints for day-ahead (DA) and hour-ahead (HA) markets. It is suggested in the paper that ramping constraints play an important roles in congestion management. Due to this type of constraints, resources scheduled in different periods in forward market congestion management cannot be determined separately as the schedules of one period will restrict scheduling in other periods. Therefore, the congestion charge would be shifted from one period to another period without considering ramping constraints.

A system of advanced analytical methods and tools for secure and efficient operation of power systems in emerging energy markets was proposed in [19]. For this purpose, the concept of the independent system operator (ISO) as a “generic” operator of an open-access transmission system was defined, so that those functions of the ISO that are essential for the security and efficiency of power system operation can be identified that would enable the ISO to perform the bulk of these functions.

A new OPF model, which is characterized by the introduction of a two-sided auction market structure with power demand elasticity while taking into account the network constraints, is proposed in [20]. In this type of market structure, the ISO has additional degrees of freedom in managing congestion conditions because load demand is now a variable. The use of the OPF is envisaged in a pool model where the ISO has a centralized dispatch function and he is also responsible for the security and the quality of operation. It is shown that OPF based on a two sided auction structure will reduces nodal price volatility and allow for congestion relief.

Transmission network plays a major role in the open access deregulated power market. In this environment, transmission congestion is a major problem that requires further consideration especially when inter-zonal/intra-zonal scheme is implemented in [21], and in [22]. A congestion problem formulation should take into consideration interactions between intra-zonal and inter-zonal flows and their effects on power systems. It is perceived that phase-shifters and tap transformers play vital preventive and corrective roles in congestion management. These control devices help the ISO mitigate congestion without re-dispatching generation away from preferred schedules. In this paper, a procedure for minimizing the number of adjustments of preferred schedules to alleviate congestion and apply control schemes to minimize interactions between zones while taking contingency-constrained limits into consideration was introduced. The paper also shows the stage where the ISO performs contingency analysis during congestion management, and shows the effect of contingency limits on congestion management. The proposed formulation could save computation time, increase the system security and apply control variables efficiently in the transmission system management to keep power system operation close to preferred schedules.

5.2.2 Congestion Pricing and Market-Based Methods

In [23], price (marginal cost) signals were used for the generators to manage congestion and the solution under rational behaviour assumption is identical to an OPF solution. A similar approach was suggested for the pool model in [24], where the cost of congestion was bundled with the marginal cost at each bus. A bilateral model was also investigated, and a congestion cost minimization approach was proposed. A framework for real-time congestion management under a marker structure similar to the newly proposed UK trading arrangement is presented in [25], in which not only resources in balancing market but also some bilateral contracts can be dispatched if necessary. The linearized model of a modified optimal power flow (OPF) is proposed to implement such a framework.

A new framework was presented in [26] to manage dynamic congestion. The main feature of the proposed model is that system stability is incorporated into the congestion management, and the concept of market-based congestion management is extended into the dynamic scenario. Under the proposed framework, the ISO can eliminate the dynamic congestion with available resources in the real-time dynamic congestion management market. The total dynamic congestion management cost will be minimized, and system security as well as the scheduled transactions are maintained.

A new congestion management system is proposed by [27], applied under nodal and zonal dispatches with implementation of fixed transmission rights (FTR) and flowgate rights (FGR), respectively. The FTR model proves to be especially suitable for congestion management in deregulated centralized market structures with nodal dispatch, while the FGR is suitable for decentralized markets. The main contribution of this work is a non-traditional valuation of FGR under a centralized market, such as those present in Latin America, that builds a link between both transmission rights under the same market structure. To accomplish that, a computational model is developed, implementing marginal theory where congestion components are introduced in the pricing model. An application to the Chilean Central Interconnected System indicates that FGR presents advantages over FTR regarding signals on grid use, but its application results in complications that make its implementation unattractive.

Service identification and congestion management are important functions of the ISO in maintaining system security and reliability [28]. Most approaches in the literature solve the problem sequentially, which may lead to an under or over-estimation of the service requirement and transaction curtailment. A few of them do it iteratively which is quite time consuming. In this paper, a combined framework for service identification and congestion management is proposed. The ideal objective function is to maximize the overall profit of all market participants. Practically, an upper bound cost minimization is suggested and has been applied to identify two of the services, the reactive support and real power loss services, in case of congestion. The service costs plus the congestion cost are minimized. Results show that the proposed approach results in a smaller transaction curtailment. The curtailment also depends on the relative cost of congestion with respect to the cost of services.

Hao and Shirmohammadi [29] presents a method and a model for managing transmission congestion based on ex ante congestion prices. The method is influenced by the yield management approach widely used for airline reservation systems, and their model is built based on the relations between transmission congestion prices and electricity commodity prices that exist for an optimal solution. They formulate the congestion pricing problem as a master problem and the electricity commodity (energy and reserve) pricing as sub-problems. Examples are presented to illustrate how a system operator can use this approach to compute ex ante congestion prices and how market operators can determine clearing prices and schedules of forward electric energy and reserve markets.

The potential for strategic bidding in deregulated electricity markets is well known. Earlier work has highlighted the role of congestion in such strategies [30], [31]. In [31], A model in which a supplier can create congestion problems in a non-congestive system even when he is the not the low cost supplier of the system is examined. If that supplier has several units located at different buses in the grid, it can profit from creating congestion under some auction mechanisms actually in use or under consideration. An integrated auction prevents profitable gaming, but requires the simultaneous handling of market clearing and system dispatch, raising concerns about the neutrality of the system operator.

A bid-based congestion management scheme for a system that accommodates many bilateral transactions was presented in [32]. The paper proposes a new allocation method for allocating the cost of congestion relief to transactions that cause the congestion. The allocation reflects the actual usage of the congested facilities by the transactions and recovers the cost. Also proposed in the paper is a "consistency" test to quantify and test the equity/fairness of the method. Test results illustrate that the method provides better price signals for relieving congestion on lines than the shadow prices. The test results also indicate that the method recovers the cost. The results on consistency indicate that the proposed method is consistent provided that the transactions causing counter-flows on congested lines be compensated.

5.2.3 Network Sensitivity Factors Methods

Other method for congestion management proved to be efficient is the use of network sensitivity factors, which is the relationship between the change in power injection and the change in power flow in the network, has been demonstrated in [33]-[39].

In a deregulated electricity market, it may always not be possible to dispatch all of the contracted power transactions due to congestion of the transmission corridors. System operators try to manage congestion, which otherwise increases the cost of the electricity and also threatens the system security and stability. In this paper, a new zonal/cluster-based congestion management approach has been proposed. The zones have been determined based on lines real and reactive power flow sensitivity indexes also called as real and reactive transmission congestion distribution factors. The generators in the most sensitive zones, with strongest and non-uniform distribution of sensitivity indexes, are identified for rescheduling their real power output for congestion management. In addition, the impact of optimal rescheduling of reactive power output by generators and capacitors in the most sensitive zones has also been studied [33].

Some closed formulas that express the contribution of each generator to the power flows, loads and losses in a power system are introduced. The derivation of the formulas is based on the sensitivity and corrective action analysis of the system. The applicability of the proposed formulas is demonstrated using various test systems and they are compared with other state-of-the-art methods. Also these formulas are tested on a practical system to relieve transmission congestion problems and calculate the use-of-transmission system charges [34].

With the separate pricing of generation and transmission, it has become necessary to find the capacity usage of different transactions occurring at the same time so that a fair use-of-transmission-system charge can be given separately to individual customers. It is also helpful to transmission congestion management if the power produced by each generator and consumed by each load could be tracked through the network, The existing proportional sharing and circuits based methods, and the newly developed power flow comparison method are introduced and compared in this paper. The power flow comparison method offers more alternatives in using available transmission capacity and pricing line flows, and provides the user with sensitivity information on how proposed corrections will affect the flows in other critical lines [35].

5.2.4 Application of FACTS Devices

An alternative to building new transmission lines to solve the frequently occurred congestion problems is to use Flexible AC Transmission System (FACTS) [40]-[44]. However, a key issue is still missing, which is the pricing scheme for the utilization of FACTS devices and penalty for users to operate at their limits. Unless this issue is addressed, no proper incentives can be provided to market participants for new constructions. A pricing scheme for FACTS devices in congestion management, which addresses both the penalty and the utilization issues, is proposed in [40]. Three different congestion management systems are, which are established in the liberalized market, described in [42]. A basic idea how to integrate load flow controlling devices (e.g. FACTS devices) in these congestion management systems in order to assess the necessary profitableness is presented.

FACTS devices such as thyristor controlled series compensators and thyristor controlled phase angle regulators, by controlling the power flows in the network, can help to reduce the flows in heavily loaded lines resulting in an increased loadability of the network and reduced cost of production [41]. Congestion management using FACTS devices requires a two step approach. First, the optimal location of these devices in the network must be ascertained and then, the settings of their control parameters optimised. The development of simple and efficient models for optimal location of FACTS devices that can be used for congestion management by controlling their parameters optimally is presented in the paper.

Although FACTS devices and unified power flow controllers (UPFCs) have proven to be powerful tools for the exploitation of network capacities, their performances with regard to transient stability have not been deeply explored yet. In this work, we propose a methodology to assess preventive control actions through adjustments of UPFC reference signals. This control action does not imply changes in the generation and load asset defined by day-ahead market laws. The representation of UPFC devices in a power system is given through a nonlinear model. The UPFC model includes electrical equivalent circuits, a local control scheme, and a centralized control scheme. Control actions are evaluated through a nonlinear optimization process. The approach is tested on a detailed representation of the Italian national grid and test results are presented [43].

Financial transmission rights (FTRs) auction is an important method for allocating the network transmission capabilities to the market participants who value them most. FACTS devices are modeled as additional power injection at buses in the presented linear optimization problem of FTRs auction, which is based on a dc power flow model [44].

5.2.5 Zonal/Cluster-Based Management Approach

The congestion management zones have been determined based on lines real and reactive power flow sensitivity indexes also called as real and reactive transmission congestion distribution factors. The generators in the most sensitive zones, with strongest and non-uniform distribution of sensitivity indexes, are identified for rescheduling their real power output for congestion management [33]. A new method has been proposed to calculate and settle zonal congestion cost in deregulated power markets, which are a mix of the pool model and the bilateral model. Based on the different settlement methods deployed, deregulated power markets can be divided into pay-as-marginal-price market, pay-as-market-clearing-price market, and pay-as-bid market. All the three kinds of markets are considered in the proposed new method by solving the same optimization problem of zonal congestion management. For a pay-as-market-clear-price market, an average shadow price has been introduced to properly charge the zonal congestion impact, while maintaining revenue neutrality of the independent system operator (ISO). This new method deploys preferred balancing energy services by solving the optimization problem of zonal congestion management. The total system ancillary energy service cost is reduced to a minimum. The market indiscrimination and the revenue neutrality of the ISO are automatically maintained in this new method [45].

Declaring that engineering studies and experience are the criteria to defining zonal boundaries, or to define a zone based on the fact that it is a densely interconnected area and paths connecting these densely interconnected areas are inter-zonal lines, will render insufficient and fuzzy definitions. The zone definition is given a certain criterion based on the locational marginal price (LMP). This concept is used to define zonal boundaries and to decide whether any zone should be merged with another zone or split into new zones. Alomoush and Shahidehpour [46] combines zonal and fixed transmission rights schemes to manage congestion. This combined scheme is utilised with LMPs to define zonal boundaries more appropriately. The scheme presented gains the best features of the transmission rights scheme, which are providing financial certainty, maximising the efficient use of the system and making users pay for the actual use of congested paths.

5.2.6 Demand-Response for Congestion Management

As we have observed, congestion relief is normally carried out through generators in the short-term by redispatching available generation to avoid congestion and other associated problems in various contingency situations. This form of congestion service provision is referred to as *preventive management* [15]. If however, the cost of such preventive management is too high, then it would be more cost-effective to invest in transmission system reinforcement which can be referred to as *long-term* congestion management. A somewhat “in-between” alternative to the above two, is to create provisions for load interruption in a judicious manner that could aid in transmission congestion relief, which can be referred to as *corrective management* [47]. In the context of deregulated markets, introducing the provision that allows customers to offer their interruptible load for competitive procurement by the ISO is a topical issue. Participation of the customers in this provision for congestion relief could significantly increase the number of service providers, and hence locations, available to the ISO. The economic validity of interruptible load depends on the difference in potential savings in congestion cost and costs involved in procuring interruptible load services offered by various consumers [17],[48]. It is demonstrated in [49] that appropriate invocation of interruptible loads by the ISO can aid in relieving transmission congestion in power systems. An auction model is proposed, for an ISO operating in a bilateral contract dominated market, for real-time selection of interruptible load offers while satisfying the congestion management objective. The *N-1* contingency criterion has been taken into account to simulate various cases and hence examine the effectiveness of the proposed method. It is shown that the method can assist the ISO to remove the overload from lines in both normal and contingency conditions in the optimal manner.

The role of demand elasticity in congestion management and pricing in a competitive electricity market was investigated in [50]. The actions of price responsive loads could be represented in terms of the customer's willingness-to-pay. From each customer's demand curve, the elasticity of the load at different prices is known and the benefit function is derived. The load at each bus ceases to be a fixed quantity and becomes a decision variable in the ISO's optimization problem. In this way, the ISO has additional degrees of freedom in determining necessary actions for network congestion management. The impact of multilateral congestion management on the reliability of power transactions is assessed in [51]. This assessment is based on reliability indices such as expected power curtailments, curtailment probability, expected cost of congestion management and probability distributions of the total power curtailment. It is demonstrated in the paper that the multilateral management results in smaller curtailments and congestion costs than traditional bilateral management.

5.2.7 Financial Transmission Rights (FTRs)

An FTR is a financial risk-management instrument. FTRs are used to hedge the costs associated with transmission congestion. It represents a specified MW amount between (usually) two points in the power transmission network. It is valid over a defined period of time, typically a month, season or year, and often only for peak or off-peak hours. Whenever there is transmission congestion in the FTR's defined direction, the FTR will earn congestion revenue for its holder from the ISO. The FTR's primary purpose is to offset a transmission user's congestion charges, which are typically quite volatile. However, in today's open FTR auctions and secondary markets, FTRs can also be arbitraged by any accredited transmission nonuser ([52]-[56]). Currently these rights are in use in PJM, New York and New England. A variant of financial transmission rights, which has both a physical and a financial aspect, was introduced in California in 2000. Similarly, flowgates were introduced in Texas in 2002 ([57]-[59]).

5.3 Congestion Management: Solution Techniques

The previous section classifies the congestion management methods by subjects or activities which need to be carried out. This section, however, attempts to look at congestion management from another angle, that is the solution techniques which are used to solve the congestion problems. Solution techniques which are available in the literature can be put into four broad categories, and are shown in Figure 5-2. The most common techniques used is the *linear programming* method, and the *dc-based* method, followed by the *decentralized* and *integrated* solution techniques. Each of the techniques are presented in details in the following section.

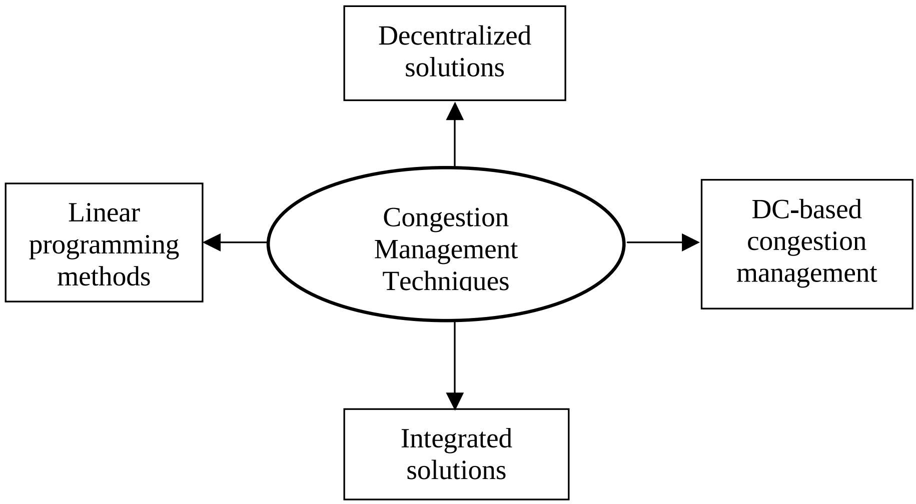

Figure 5-2: Solution techniques for congestion management

5.3.1 Linear Programming Methods

In [60], an augmented Lagrangian relaxation based algorithm for regional decomposition optimal power flow (OPF) is presented to address congestion management across interconnected regions. An OPF problem is decomposed into regional sub-problems through Lagrangian relaxation. Unlike other existing methods, no dummy generators or loads are added into the original network model. Applying this algorithm with the real-time balancing mechanism, the problem of active power congestion management across interconnected regions is separated into quadratic regional sub-problems, which can be solved either sequentially or in parallel. With this approach, regional ISOs can relieve network congestion co-ordinately without knowing any other regions' network information but the corresponding Lagrangian multipliers of coupling constraints between regions.

A new framework of real-time congestion management under a deregulation environment is discussed in [61], in which not only resources in balancing market but also some short-term bilateral contracts can be dispatched if necessary. The real-time reactive power and voltage support is also included in this framework. The linearized model of a modified decoupled optimal power flow is proposed to implement such a framework. A primal-dual interior point linear programming method with second-order predictor-corrector techniques is applied to solve this optimization problem efficiently.

In [62], an efficient and practical hybrid model has been proposed for congestion management analysis for both real and reactive power transaction under deregulated power system environments. The proposed hybrid model determines the optimal bilateral or multilateral transaction and their corresponding load curtailment in two stages. In the first stage classical gradient descent optimal power flow algorithm has been used to determine the set of feasible curtailment strategies for different amount of real and reactive power transactions. Whereas in the second stage, a fuzzy decision opinion matrix has been used to select the optimal transaction strategy considering increase in private power transaction, reduction in percentage curtailment, and its corresponding change in per unit generation cost and hence profit as fuzzy variables.

5.3.2 DC-Based Congestion Management

It is difficult to arrive at the exact solutions of the complex network calculations within a short time, especially during the operation of power systems. It can therefore be seen from the literature that approximation of the network based on *dc-load flow* is a preferred technique in many congestion management due to its simple nature in calculation while giving the results with reasonable accuracy [51], [63]-[65].

5.3.3 Integrated Solution

The rapid growth of inter-regional trading among electricity markets requires the development of new market-oriented mechanisms for the inter-regional congestion management of such trading [66]. An alternative approach to inter-regional trade that avoids the flaws of forward markets with explicit auctioning of interconnections capacities is proposed. We propose the integration of a forward market with a balancing (spot) market for inter-regional exchanges based on nodal pricing. The interaction of transmission system operators (TSOs) belonging to adjacent markets is efficiently taken into account through a decentralized OPF, which is solved by interior point methods.

The problem of inter-ISO congestion management using optimization-based techniques is address in [67]. This requires the coordination of involved ISOs and raises the problem of how different network operators will coordinate their operations to achieve system-wide efficiency. An auction mechanism have been proposed, and test results show that system-wide efficiency can be achieved using a decentralized and coordinated optimization-based approach.

Two multivariate methods (correlation analysis and principal components analysis) are used to forecast which lines may be simultaneously congested [68]. These statistical methods are applied to a database which takes into account transmission planning uncertainties such as localization of new independent power producers and new eligible customers (*i.e.*, customers who can choose their energy supplier), and level of international exchanges. To face the very large number of possible configurations, a design of experiment is used to create the data base. A complete active/reactive-power flow program is used to simulate the power system. Knowing which lines will be simultaneously congested may help the system operator to take decision in short-term operation (congestion management) as well as in long-term planning (grid reinforcement).

5.3.4 Decentralized Solutions

Methods for the decentralised solutions of the congestion management problem in large interconnected power systems are proposed in [69] and [70]. The multi-area congestion management is achieved through cross-border co-ordinated redispatching by regional transmission system operators. The coordination is performed through a pricing mechanism inspired by Lagrangian relaxation. The prices used for the co-ordination of the regional sub-problem solutions are the prices of electricity exchanges between adjacent areas.

5.4 Congestion Management Around-The-World

The state-of-the-art in congestion management distinguishes the available methods and practices into two fundamental schools of thoughts. One is based on flow gate (FG) (transmission path reservation) [74] and the other based on central optimum dispatch [23], [75] and [76]. In the FG approach, firm transmission rights for transmission paths are acquired or traded well in advance of actual power delivery date and are priced independently from the energy and reserve markets. The FG approach is more consistent with traditional transmission reservation practices and is highly desirable, especially for bilateral markets due to the certainty of transmission reservation and prices. However it may not lead to optimum use of transmission system capacity and is incompatible with the operation of a pool electricity market. In a central optimum dispatch, mainly used in pool markets, transmission congestion management is performed as part of the optimum dispatch of system resources, and congestion pricing is the by-product of the optimum dispatch. In this approach, while transmission system is optimally used, lack of certainty in transmission capacity and prices is considered detrimental to the development and operation of the overall electricity markets.

5.4.1 Nordic Markets

In the Nordic electricity market, market-adapted methods are used to manage bottlenecks, *i.e.*, market splitting and counter-trade. Both principles are used simultaneously in the joint market, primarily at national borders. It was decided not to rectify anticipated bottlenecks on the grid during the planning phase, instead dealing with them during the operation phase in real-time using counter-trading in Sweden [72].

A. Market splitting:

Market splitting is used to limit transmission at just a few determined borders, primarily borders between countries, and internally in Norway. Market splitting is carried out by NordPool. The auction principle on the spot market enables the management of potential bottlenecks on the network during the operational planning phase (*i.e.*, the day prior to delivery). The market is divided up into different price areas. The different prices in the areas provide the players with signals for once again planning their production or consumption. After the spot market has held its auction, the ensuing trade can indicate that the transmission of electricity through a bottleneck will exceed the capacity. The market is then split and separate prices and volumes for the different areas are worked out. The ISOs then ensure that the network capacity at the bottleneck is utilized by adjusting the estimated price in the low-price area. The volume of electricity which may be transmitted is included when the price for the high-price area is calculated.

B. Counter-trade

This is practiced in Sweden wherein, if transmission needs to be reduced between two areas within Sweden, an increased level of electricity production can be ordered in the area with a shortage of production at the same time as a decreased level of production in the area with a surplus. This is known as counter-trade and is carried out with the assistance of the *balance service*. Counter-trade is used during the delivery hour (*i.e.*, real-time) in order to deal with bottle necks, which can arise anywhere on the network. Via the balance service the ISO receives information about resources in order to be able to regulate the balance at different geographical locations.

5.4.2 Spain

The Spanish electricity market as it started on 1st January, 1998 is based on two separate entities: the market operator (MO) and the system operator (SO). The MO receives the bidding of generation and demand for each hour of the following day and clears the market according to economic criteria. The SO is responsible for the secure operation of the power system and owns the transmission system. One of the main tasks of the SO consists of solving the power system constraints that arise after the market has been cleared [4]. Power system constraints are addressed by increasing and decreasing the generation of connected units, and by connecting off-line ones. Power system constraints are solved in Spain minimizing the system cost variation of the initial market clearing, fullfilling the power system security criteria. The units that increase their output are paid at their bid prize. Generators that decrease their output are not compensated for their income reduction. Therefore, the total system cost is computed by adding the bid cost of new connected generation, and subtracting the decreased energy times the system marginal price. The SO computes the unit re-dispatch taking into account the bids submitted by the generating agents into the market. A generation bid consists of a set of power-prize blocks for each hour of the following day. A minimum income complex condition is also submitted in the bid. This condition consists on a fixed income term and a variable income term. The fixed term internalizes the start up cost of the thermal generating units.

As has been established in the market rules, both the SO and the MO participate in the solution procedure. The generation re-dispatch determined by the SO to solve power system constraints is sent to the MO. It should be noted that the SO must submit to the MO only the variation of generation needed to eliminate power system constraints. The MO includes the re-dispatch provided by the SO in the initial market clearing, and restores the generation-demand balance by adjusting the least expensive units according to the bids submitted by the agents. The security criteria of the Spanish power system require that power system variables (system frequency, branch power flows and bus voltages) are within their limits not only in normal operating conditions but also when any credible contingency occurs [15]. The contingencies under consideration are the loss of any single transmission line, generator or transformer, the loss of the double circuits that share more than 30 km and the combined loss of certain generators and transmission lines. Spanish regulation imposes a preventive operation of the power system for these postulated contingencies. Of course, branch and bus limits in case of *N-1* and *N-2* contingencies are different than the limits under normal operating condition. Branch power flow limits also depend on the season of the year.

5.4.3 North America

A. ERCOT (Texas)

ERCOT uses a zonal, portfolio-based model that classifies the region into zones and identifies the commercially significant interfaces between the zones as Commercially Significant Constraints (CSC). In 2001 there were three zones and two CSC while in 2002 there were four zones and four CSC. Implicit assumptions under the ERCOT zonal model include [73], [78]:

- All generators in a zone have the same shift factors with respect to CSC
- A generator in one zone does not impact local congestion in other zones (zero shift factor on out of zone lines)

ERCOT solves *zonal and local congestion* in two steps, in conjunction with a security constrained dispatch. In the first step, ERCOT clears the predefined CSC congestion, dispatches zonal balancing energy, sets the shadow price of each CSC, and determines the market clearing price for each congestion zone. Balancing Energy Service offers are procured by ERCOT in each zone for zonal load balancing and for inter-zonal congestion relief. The market clearing price for energy (MCPE) is determined in each zone based on the portfolio of zonal offer curves for balancing energy. If there is no zonal congestion, the MCPE is the same for the entire ERCOT region. In the second step, ERCOT uses resource specific premiums to clear local constraints and to issue resource specific instructions to relieve local congestion, and it uses additional resource specific instructions to rebalance the zonal energy. These resource specific instructions are called “Local Balancing Energy Service.” Generators submit resource specific premiums that specify the additional payments (in addition to the zonal MCPE) that they require for the deployment of incremental or decremental balancing energy from the associated, specific resource, if a Market Solution exists. However, more than 90 percent of the time in 2001 and 2002 a Market Solution did not exist. When a Market Solution does not exist, ERCOT issues out-of-merit (OOM) dispatch instructions. Generators who provide OOM services are paid for production costs based on Resource Category Generic Fuel Cost, Resource Category Generic Startup Cost and Resource Category Generic Operational Cost can work well. If there is substantial local congestion, the simplified assumptions imbedded in the zonal model may break down, and pricing of a large number of transmission constraints may be needed for efficient dispatch and location of new resources.

B. PJM ISO

In PJM, FTRs are available to firm point-to-point and network transmission customers as a hedge against congestion charges. The firm transmission customers have access to FTRs because they pay the cost of the transmission network that makes firm energy delivery possible. Individual firm transmission customers receive FTRs to the extent that they are consistent both with the physical capability of the transmission system and with the other firm transmission customers' requests for FTRs [58], [77].

In June 2003, PJM replaced the direct allocation of FTRs with an allocation of Auction Revenue Rights (ARRs) coupled with an Annual FTR Auction. The annual FTR auction permits market participants to bid for the FTRs and thus provides a market-based determination of both ARR and FTR value. Both ARRs and FTRs are financial instruments that entitle the holder to receive revenues (or pay charges) based on nodal price differences. The value of the ARRs is based on differences in nodal prices across selected paths that result from the Annual FTR Auction. The price of FTRs is determined by the auction results. The value of the FTR hedge is a function of the nodal prices in the hourly Day-Ahead Energy Market. ARR and FTR holders do not need to deliver energy to receive ARR or FTR credits, and neither instrument represents a right to the physical delivery of power. Both can, however, protect load-serving entities (LSEs) and other market participants from uncertain costs caused by transmission congestion in the PJM Day-Ahead Market. Market participants can also hedge against real-time congestion by matching real-time energy schedules with day-ahead energy schedules.

C. California ISO:

In the California market, a FTR is defined as a 1-MW portion of the available transmission capacity (ATC) on a specific inter-zonal transmission interface or inter-tie, going in one direction only, from an originating zone to a contiguous receiving zone. FTRs have both a financial and physical attribute. The financial attribute entitles the owner to a share of the path's congestion revenues, and as such, they provide a financial hedge for scheduling on that path. The physical aspect pertains to the fact that the day-ahead energy schedules of FTR holders have higher priority against curtailment than the schedules of non-FTR holders. However, there is no FTR scheduling priority in the hour-ahead market. The CAISO does not require that FTR owners be CAISO scheduling coordinators (SCs). FTRs may be purchased by any qualified bidder purely as an investment to enable the owner to receive a stream of income from the congestion usage revenues. In order to be used in scheduling, however, an FTR must be assigned to one of the SCs. In addition, an owner may resell the FTR or the scheduling rights may be unbundled from the revenue rights and sold or transferred to another party [59].

Intra-zonal congestion can occur either in areas where generation is clustered together, with insufficient transmission access to allow the energy out, or where load is concentrated with insufficient transmission access to allow competitively priced energy in. In both cases, the absence of sufficient transmission access to that area means that the CAISO has to resolve the problem locally, either by incrementing generation within the area if there is not enough, or by decrementing it if there is too much. The CAISO's current method for dealing with incremental intra-zonal congestion is by dispatching available RMR energy in real-time in the first instance. Should that energy be insufficient, other units are then dispatched out-of-sequence (OOS) if they have submitted real-time imbalance energy market bids, or out-of-market (OOM) if they have not. OOS dispatches are so called because they require the CAISO, when incrementing [decrementing] generation, to bypass lower [higher] priced, in-sequence, real-time bids to find a unit whose grid location enables it to mitigate a particular intrazonal congestion problem. Units incremented [decremented] OOS to mitigate intrazonal congestion are paid the higher [lower] of their bid price [reference level] or the zonal market clearing price, and do not set the real-time market-clearing price.

Inter-tie bids taken OOS are paid-as-bid. Available thermal units within the CAISO control area are subject to the must-offer obligation (MOO) whereby incremental energy bids are automatically inserted for them if they fail to do so themselves. There is no MOO for decremental energy bids. The provisions of Amendment 50 allow the CAISO to decrement generation for intrazonal congestion using bid-reference levels supplied by an independent entity.

D. New England ISO:

Congestion on the New England system was generally low, driven by two factors- lower-than-normal system peak demand during the summer months and fuel prices for gas units outside of load pockets increased relative to fuel prices for oil units within load pockets. This decreased the difference between the offer prices of the two types of generators on either side of constrained interfaces, thereby lessening the amount of financial congestion realized. When congestion occurred in the Day-Ahead Market, it was often due to levels and patterns of cleared day-ahead demand (fixed, price-sensitive, and virtual) and not due to constraints that would be expected during real-time operations [57].

Congestion hedging through Financial Transmission Rights– under standard market design (SMD), market participants are able to buy financial instruments that help them to hedge the price risk of day-ahead congestion caused by constraints on the transmission system. FTRs were offered to the marketplace in 10 ISO-administered monthly auctions and one three-month auction during 2003.

Participation in the auctions was strong and market participants purchased FTRs consistent with expected patterns of congestion. Winning auction bids generated $28.5 million in revenue for auction rights holders, and the monthly and long-term FTRs awarded during the year provided over $84 million of day-ahead congestion cost offsets to their holders.

Transmission congestion in the day-ahead market can cause prices to vary across the power grid. This causes more revenue to be collected from load in congested areas. To protect or "hedge" against the expense of higher LMPs, market participants may bid for the rights to receive a share of this congestion revenue. FTRs are financial instruments that entitle the holder to a share of congestion collections in the day-ahead market.

In any hour, an FTR may result in either payments due or payments owed. Specifically, a participant holding an FTR defined from Point A to Point B will be entitled to compensation only if the hourly congestion component of the LMP at Point B is higher than that at Point A. If the hourly congestion component is higher at Point A, the FTR becomes a liability. In this case, the FTR holder is obligated to pay the congestion cost. FTRs can be acquired in three ways:

- FTR Auction– the ISO conducts periodic auctions to allow bidders to acquire and sell monthly and long-term FTRs. All FTRs are initially defined by the bidders in the FTR auction.
- Secondary Market– The FTR secondary market is an ISO-administered bulletin board where existing FTRs are electronically bought or sold on a bilateral basis.
- Unregistered Trades– FTRs can be exchanged bilaterally outside the ISO-administered process. However, the ISO compensates only FTR holders of record and does not recognize business done in this manner for day-ahead congestion settlement purposes.

The effectiveness of FTRs as a congestion hedge by participants was mixed. In general, FTR auction prices should correlate with Day-Ahead Market congestion, which in turn should be a reflection of real-time congestion expectations on the system. A combination of recent changes to the transmission system, generation infrastructure, the ISO's need to commit units for real-time reliability, and participant market strategies, including risk management approaches, all affect the patterns of congestion on the system, and therefore the FTR auctions.

F. Summary

FTRs are used to hedge the costs associated with transmission congestion. Currently these rights are in use in PJM, New York and New England. A variant of FTR, which has both a physical and a financial aspect, was introduced in California in 2000.

Some systems rely on distinctions among the priorities assigned to various contractual entitlements to transmission. In 1999, the California ISO auctioned annual contracts (which took effect in February 2000) for FTR for day-ahead inter-zonal capacity on that portion assigned to the ISO by the investor-owned utilities. These rights amount to about 50 percent of the ISO's average capacity available daily, and nearly 100 percent of a conservative estimate of the capacity available annually (*i.e.*, for the entire year), net of contracts existing when the market was established in 1998 and expiring in later years.

These FTRs differ from the "fixed transmission rights" issued by PJM, which are purely financial contracts entitling each owner to a refund of the difference in nodal prices on a specific point-to-point path. PJM's rights are allocated by an optimization in which bids for point-to-point transmission are used to simulate energy flows. Secondary markets for point-to-point financial rights are too thin to be viable, so PJM offers a monthly re-configuration process as a substitute. Financial rights suffice to meet FERC directives requiring each system operator to provide a means for customers to ensure "price certainty" if private markets for hedges against transmission prices is insufficient, as invariably they have been.

California issues firm transmission rights for each direction for each interface between zones, including import/export interfaces. These rights can be assigned or traded in secondary markets. Like PJM's hedges, firm transmission rights include financial components because they provide refunds of inter-zonal usage charges, although these refunds are nil in the specified direction if congestion is in the reverse direction (*i.e.*, no credit is given for counter flows).

The transformation from a nodal or zonal system into a flow-based system is relatively straightforward. It can be accomplished by using the power transfer distribution factors as the exchange rates to translate transmission rights from one system to another without significantly affecting the existing market processes and institutions. After translating into a flow-based system, the main difference between the nodal- and zonal-based rights lies in the different numbers displayed in the PTDF matrix. Immediately, this will obviate the need for bid reconfiguration in PJM and rezoning in California (for intra-zonal congestion problems).

5.5 Conclusions

This chapter presents a systematic and comprehensive review of the current research trends in the issues related to transmission congestion management, as well as its practical implementation in the deregulated electricity markets around the world. It should be noted that depending on the structure and objectives of the electricity market, different congestion management methods are put into practice. Effective congestion management will help mitigate the effects of market power in electricity markets [1],[71],[17]. Attempt has been made to cover most major research publications on transmission congestion management in deregulated electricity markets. This list is by no means complete. It could, however, serve as an essential guideline and a succinct account for any researcher who wishes to work in this challenging field.

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CHAPTER 6 *

INTERRUPTIBLE LOAD SERVICES FOR TRANSMISSION CONGESTION MANAGEMENT

This chapter presents two approaches to congestion management using interruptible loads. The first approach is based on an AC optimal power flow framework which can be used for the real-time selection of interruptible load offers while satisfying the congestion management objective. The method is based on the calculated factors, termed as congestion relief indices (CRI) determined for each bus with respect to a particular line and specifically denote the "relief ability" of a load with respect to a certain transmission line. The first method does not utilize the constraints on power flow, and hence in some cases, the model is not able to remove all transmission congestion. The second approach proposed, is based on a dc optimal power flow framework, and overcomes the drawback of the first approach. The proposed congestion management scheme using interruptible loads can specifically identify load buses where corrective measures are needed for relieving congestion on a particular transmission corridor. The N-1 contingency criterion has been taken into account to simulate various cases and hence examine the effectiveness of the proposed method. It has been shown that the method can assist the ISO to remove the overload from lines in both normal and contingency conditions in an optimal manner.

6.1 Introduction

The present chapter proposes an integrated technical-cum-market based framework for congestion management, which uses interruptible load services as a tool for the ISO to provide transmission congestion relief in the dispatch stage.

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L.A. Tuan and K. Bhattacharya, "Interruptible Load Services for Transmission Congestion Relief", in Proc. of 14th Power Systems Computation Conference (PSCC '02), Sevilla, Spain, June 24-28, 2002.

L.A. Tuan, K. Bhattacharya and J. Daalder, “Transmission Congestion Management in Bilateral Markets: An Interruptible Load Auction Solution”, *Electric Power Systems Research*, in print.

This chapter develops a scheme for the ISO to identify those buses in the system that can effectively influence the power flow over a particular transmission line. These factors termed as *congestion relief indices* (CRI), are determined for each bus and specifically denote the "relief ability" of a load with respect to a certain transmission line.

The task of the ISO now is to find the most effective set of loads to be curtailed, both in terms of transmission relief and financial compensation. The ISO operates an interruptible load service market in the dispatch stage, one-hour ahead of real-time. In this market, interruptible load participants offer their interruption capability for the next hour and their associated price offer.

In the first approach, based on the obtained CRI and submitted offer information from interruptible load participants, a Congestion Relief Model (CRM) is executed every hour to obtain the optimal interruption schedule for transmission congestion relief. The second approach is much simpler than the first one, in the sense that no calculation of CRI is required. The model addresses the congestion problem by incorporating transmission constraints. The interruptible load contracts are selected against that constraint, among others. By this way, with enough invocation of interruptible loads, transmission congestions are completely removed from lines. The following sections will present the two approaches proposed and simulation results of both cases.

6.2 Congestion Management using Sensitivity Factors

6.2.1 Transmission Congestion Relief Index (CRI): Mathematical Formulation

A set of parameters that determine the sensitivity of power flow on a line to load reduction at a bus is developed and presented in this section. These are termed as "Congestion Relief Index". Let us consider the basic power flow equations:

$$\Delta P_i = P_{g_i} - P_{d_i} = \sum_{j,\, j\neq slack} |V_i||V_j|Y_{ij}\cos(\theta_{ij} + \delta_j - \delta_i) \tag{1}$$

$$\Delta Q_i = Q_{g_i} - Q_{d_i} = -\sum_{j,\, j\neq \mathrm{slack}} |V_i||V_j|Y_{ij}\sin(\theta_{ij} + \delta_j - \delta_i) \tag{2}$$

ΔP_i and ΔQ_i denote the injections of active and reactive power respectively at bus i.

The power flow on line *i-j*, connecting bus *i* and bus *j*, can be calculated using:

$$P_{ij} = V_i \cos\delta_i \{\mathrm{Re}(I_{ij})\} + V_i \sin\delta_i \{\mathrm{Im}(I_{ij})\} \tag{3}$$

$$Q_{ij} = V_i \sin\delta_i \{\mathrm{Re}(I_{ij})\} - V_i \cos\delta_i \{\mathrm{Im}(I_{ij})\} \tag{4}$$

where, Re(I_{ij}) and Im(I_{ij}) are the real and imaginary parts, respectively, of the line current on the transmission line *i-j*, corresponding to the power flow P_{ij}. These are given below:

$$\mathrm{Re}(I_{ij}) = V_i Y_{ij} \cos(\theta_{ij} + \delta_j) - V_i Y_{ij} \cos(\theta_{ij} + \delta_i) + V_i Y_{ch_{ij}} \sin\delta_i \tag{5}$$

$$\mathrm{Im}(I_{ij}) = V_j Y_{ij} \sin(\theta_{ij} + \delta_j) - V_i Y_{ij} \sin(\theta_{ij} + \delta_i) + V_i Y_{ch_{ij}} \cos\delta_i \tag{6}$$

Replacing (5) and (6) in (4) we have:

$$P_{ij} = V_i V_j Y_{ij} \cos(\theta_{ij} + \delta_j - \delta_i) - V_i^2 Y_{ij} \cos\theta_{ij} + V_i^2 Y_{ch_{ij}} \sin 2\delta_i \tag{7}$$

$$Q_{ij} = -V_i V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) + V_i^2 Y_{ij} \sin\theta_{ij} - V_i^2 Y_{ch_{ij}} \cos 2\delta_i \tag{8}$$

Applying Taylor series approximation to (7) and (8), respectively, we can write:

$$\Delta P_{ij} = \frac{\partial P_{ij}}{\partial \delta_i}\Delta\delta_i + \frac{\partial P_{ij}}{\partial \delta_j}\Delta\delta_j + \frac{\partial P_{ij}}{\partial |V_i|}\Delta V + \frac{\partial P_{ij}}{\partial |V_j|}\Delta V_j \tag{9}$$

$$\Delta Q_{ij} = \frac{\partial Q_{ij}}{\partial \delta_i}\Delta\delta_i + \frac{\partial Q_{ij}}{\partial \delta_j}\Delta\delta_j + \frac{\partial Q_{ij}}{\partial |V_i|}\Delta V + \frac{\partial Q_{ij}}{\partial |V_j|}\Delta V_j \tag{10}$$

Equation (9) and (10) can be re-written in terms of a set of coefficients as follows:

$$\Delta P_{ij} = a_{ij}\Delta\delta_i + b_{ij}\Delta\delta_j + c_{ij}\Delta V_i + d_{ij}\Delta V_j \tag{11}$$

$$\Delta Q_{ij} = a'_{ij}\Delta\delta_i + b'_{ij}\Delta\delta_j + c'_{ij}\Delta V_i + d'_{ij}\Delta V_j \tag{12}$$

The coefficients appearing in (11) and (12) can be obtained using partial derivatives of the real and reactive power flow relationships given in (7) and (8) respectively, with respect to the variables δ and *V*. These coefficients are given below:

$$a_{ij} = V_i V_j Y_{ij} \sin\left(\theta_{ij} + \delta_j - \delta_i\right) + 2V_i^2 Y_{ch_{ij}} \cos 2\delta_i \tag{13}$$

$$b_{ij} = -V_i V_j Y_{ij} \sin\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{14}$$

$$c_{ij} = V_j Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i\right) - 2V_i Y_{ij} \cos\delta_{ij} + 2V_i Y_{ch_{ij}} \sin 2\delta_i \tag{15}$$

$$d_{ij} = V_i Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{16}$$

$$a'_{ij} = V_i V_j Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i\right) + 2V_i^2 Y_{ch_{ij}} \sin 2\delta_i \tag{17}$$

$$b'_{ij} = -V_i V_j Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{18}$$

$$c'_{ij} = -V_j Y_{ij} \sin\left(\theta_{ij} + \delta_j - \delta_i\right) + 2V_i Y_{ij} \sin\delta_{ij} - 2V_i Y_{ch_{ij}} \cos 2\delta_i \tag{19}$$

$$d'_{ij} = -V_i Y_{ij} \sin\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{20}$$

Again, let us consider the basic power flow equations (1) and (2) and apply Taylor's Series expansion. We get the well known matrix-vector relationship in terms of the Jacobian matrix J as given below:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = [\mathrm{J}] \begin{bmatrix} \Delta\delta \\ \Delta|V| \end{bmatrix} = \begin{bmatrix} J_{11} & J_{12} \\ J_{21} & J_{22} \end{bmatrix} \begin{bmatrix} \Delta\delta \\ \Delta|V| \end{bmatrix} \tag{21}$$

J_{11}, J_{12}, J_{21}, J_{22} are appropriate sub-matrices of the Jacobian matrix J derived from the Taylor Series approximations.

Neglecting the coupling between ΔP and $\Delta|V|$ and between ΔQ and Δδ we can simplify (21) as follows:

$$[\Delta P] = [J_{11}][\Delta\delta] \tag{22}$$

and

$$[\Delta Q] = [J_{22}][\Delta|V|] \tag{23}$$

In this problem discussed, we will neglect the reactive power flows in the system in order to keep the computational burden low, and in order to explain the proposed method as well as to demonstrate the case study better. Reactive power flow equations can, however, be easily incorporated in this method without any difficulty.

Then we can write from (22):

$$[\Delta\delta] = [J_{11}]^{-1}[\Delta P] = [M][\Delta P] \tag{24}$$

where, [M] is the inverse of matrix [J_{11}].
or,

$$\Delta\delta_i = \sum_{j=1}^{n} m_{ij}\Delta P_j \tag{25}$$

Since we have neglected the couplings ΔP - $\Delta|V|$ and ΔQ - $\Delta\delta$, and also the reactive power flow, we can simplify (9) and hence (11), while neglecting (10) and (12), to get:

$$\Delta P_{ij} = a_{ij}\Delta\delta_i + b_{ij}\Delta\delta_j \tag{26}$$

Using (25) and (26) we can write:

$$\Delta P_{ij} = a_{ij}\sum_{l=1}^{n} m_{il}\Delta P_l + b_{ij}\sum_{k=1}^{n} m_{jk}\Delta P_k \tag{27}$$

$$\Delta P_{ij} = \left(a_{ij}m_{i1} + b_{ij}m_{j1}\right)\Delta P_1 + \left(a_{ij}m_{i2} + b_{ij}m_{j2}\right)\Delta P_2 + \ldots + \left(a_{ij}m_{i_n} + b_{ij}m_{j_n}\right)\Delta P_n \tag{28}$$

Defining $CRI_{ijk} = a_{ij}m_{ik} + b_{ij}m_{jk}$ we can have the following important equation:

$$\Delta P_{ij} = CRI_{ij1}\Delta P_1 + CRI_{ij2}\Delta P_2 + \ldots + CRI_{ijk}\Delta P_k + \ldots + CRI_{ijn}\Delta P_n \tag{29}$$

Equation (29) denotes that the change in the power flow on a transmission line from a bus *i* to bus *j* is affected by the change in the power injection at a bus. CRI_{ijk} denotes how much the active power flow over a transmission line *i-j* would change with a unit change in active power injection at bus *k*. High value of CRI_{ijk}

indicates that the change in power injection at a bus *k* will have high influence on the power flow on line *i-j*.

Now, if ΔP_{ij} is the overload power (*i.e.*, the amount above the line transfer capability limit) on line *i-j*, the job of the ISO is to remove this violation of power flow limit. The ISO would consider choosing to change active power injections at those buses whose *CRI* values are substantially high in order to manage the congestion. Since we assume that the power generation at a bus is not changing, thus, change in active power injection is nothing but the change in active power demand at this bus. Thereby, we now refer the change in the real power injection at a bus as real power demand reduction or interruption at that bus.

It is noted that the treatment presented above draws on the same approach as discussed in [1] and the CRI is similar to the power transfer distribution factor (PTDF) as described in [2].

6.2.2 Optimal Contracting of Interruptible Load

From (29) in Section 6.2.1, we have an explicit relation governing the change in power flow on a line *i-j* and change in real power injection at each bus *i*, using *CRI*.

With this information available *a priori* with the ISO, since it can be easily determined from a base case load flow run every hour, the task of the ISO is to manage an interruptible load market for transmission congestion relief. The various objectives of the ISO can be summarized as follows:

- Total line power flow violations from contracted transactions is minimized;
- Total ancillary service cost (which is the total payment to the selected interruptible load offers) is minimized;
- Mandatory requirements on maintaining a minimum level of operating reserve is satisfied;
- All system operating constraints are within their limits.

For the sake of continuity, we assume the same characteristics of interruptible load participants with regard to their offer price trends as that in Chapter 4 (see Figures 4-2) in response to system operating reserve forecast information.

The optimal interruptible load contracts will be based on selected offers, specifying the interruption called for, from each customer type at each hour in real-time. Each selected offer will be paid the uniform price, which is the highest accepted offer price. The market structure proposed here is similar to the one proposed in Chapter 4 (see Figure 4-1) and works on an hour-ahead basis.

Figure 6-1 shows the working scheme of the proposed optimal constructing scheme for interruptible loads to aid in congestion relief, in which the ISO has to execute two consecutive models for every hour in a day:

- The basic load flow model (LFM) is to be executed every hour to determine the lines which are congested and *CRI* at every load bus. *CRI* will be used in the congestion relief model;

- The congestion relief model (CRM), which is a modified OPF model, includes the interruptible load offers characteristics as discussed in Section 4.3.2 (Figure 4-2). The objective is minimization of a *compromise objective*, including total line violations and ancillary service payment by the ISO to the selected interruptible load offers. The *CRIs* calculated from LFM are used in the objective function of CRM. CRM determines the uniform price to be paid to all interruptible load offers by the ISO and the total amount of load to be interrupted for each selected offer in the next hour.

A. The Load-Flow Model

The basic load flow equations, modified to include the power generation and demand separated according to those through bilateral contract and those traded in the spot market, is as follows:

$$\Delta P_i^{(LFM)} = PG_{i,m} + PG_{i,b} - PD_{i,m} - PD_{i,b} = \sum_{j,\ j\neq slack} |V_i||V_j|Y_{ij}\cos\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{30}$$

$$QG_i - QD_i + QC_i = -\sum_{j,\ j\neq \text{slack}} |V_i||V_j|Y_{ij}\sin\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{31}$$

The left-hand side of the equation (30) denotes the active power injection at bus *i*. From the LFM, those lines which are overloaded will be identified. The simulation of bilateral contracts for generation and demand is presented in detail in Appendix 1.

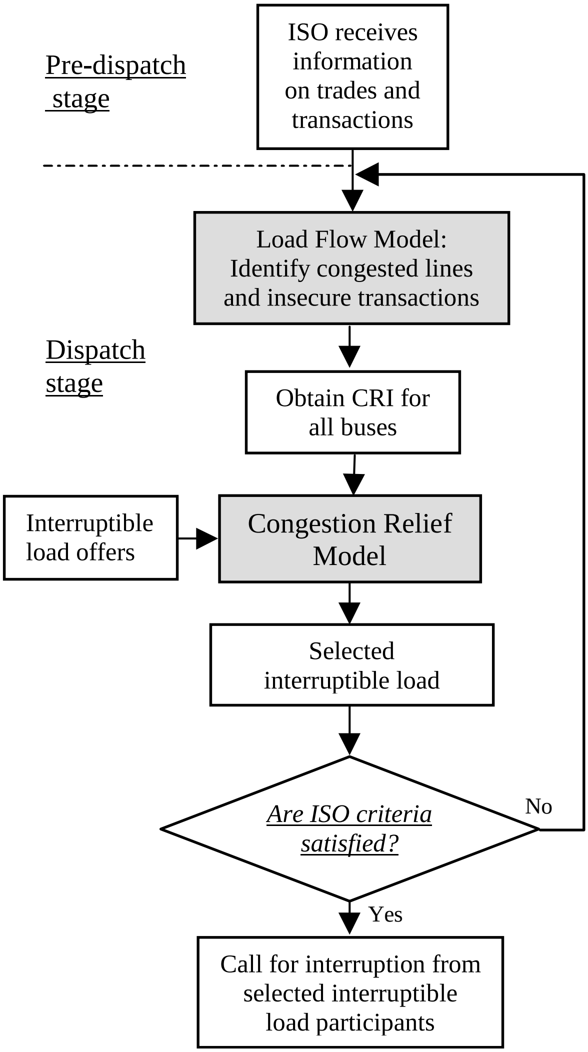

Figure 6-1: Schematic diagram of the proposed transmission congestion management framework

B. The Congestion Relief Model

Objective Function:

From equation (29) and our earlier discussion, ΔP_{ij} depends on the change in power injection at a bus, which is virtually the load interruption at a bus ΔP_k. The objective of the ISO is to minimize the amount of congestion over the transmission system by selecting to interrupt appropriate load buses. The *CRIs* identified in load flow model is used in the congestion management objective, which is to minimize total line flow violations:

$$VIOL = \sum_{i,j} \Delta P_{ij} = \sum_{i,j} \sum_{k} CRI_{ijk} \cdot \Delta P_k \tag{32}$$

The objective of the ISO is also to minimize the service cost for each hour paid to interruptible load customers selected for their demand interruptions. This is because if the objective function is only for reducing the congestion, the ISO would end up with paying a very high price for the interruption cost. The payment objective is:

$$Payment = \sum_{i} \left(\rho \cdot \Delta PD_i \right) \tag{33}$$

Note that ρ is the uniform interruptible load pay-price that is determined by CRM and is payable to all interruptible load offers invoked by the ISO.

A compromise objective function is then formulated, combining the above two objectives as defined by (32) and (33), to satisfy the overall objective of the ISO, which is to minimize total line flow violations as well as total payment paid to the interruptible load offers.

$$OBJ = \sqrt{\left(\frac{VIOL}{VIOL^*} \right)^2 + \left(\frac{Payment}{Payment^*} \right)^2} \tag{34}$$

$VIOL^*$ and $Payment^*$ are the minimum values of violations and payment, respectively, when these objective functions are individually minimized. These are already known before the compromise optimization program is solved.

Load Flow Equations:

$$\Delta P_i^{(CRM)} = \sum_{j,\, j \neq slack} |V_i||V_j| Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i \right) \tag{35}$$

$$QG_i - QD_i + QC_i = - \sum_{j,\, j \neq \mathrm{slack}} |V_i||V_j| Y_{ij} \sin\left(\theta_{ij} + \delta_j - \delta_i \right) \tag{36}$$

The left-hand side of Equation (35) denotes the active power injection at a bus i. The change in power injection in CRM and LFM is the power interruption at a bus. Thus:

$$\Delta PD_i = \Delta P_i^{(CRM)} - \Delta P_i^{(LFM)} \tag{37}$$

Upper and Lower Limits on Buses Voltages:

$$\left| V_i \right| = \text{constant}, \quad \forall i = 1,\ldots, NG \tag{38}$$

$$V_i^{\min} \leq \left| V_i \right| \leq V_i^{\max}, \quad \forall i = 1,\ldots, NL \tag{39}$$

Upper and Lower Limits on Reactive Power Support:

$$QC_i^{\min} \leq \left| QC_i \right| \leq QC_i^{\max}, \quad \forall i = 1,\ldots, NL \tag{40}$$

Operating Reserve Constraints: This constraint ensures that a pre-specified and mandatory minimum level of operating reserve is maintained at all time.

$$\sum_i^{NG} PG_i^{\max} \cdot UC_i - \sum_i^{NL} PD_i + \sum_i^{ILM} \Delta PD_i \geq RES \tag{41}$$

Limit on Interruption: Each interruptible load offer is represented in the model by a binary integer variable. The total interruption invoked by the ISO from is limited by the offered quantity:

$$\Delta PD_i \leq \mu_i \cdot U_i, \quad \forall i = 1,\ldots, NILM \tag{42}$$

The quantity offered by an interruptible load market participant is limited by the total demand at its disposal.

$$\mu_i \leq a_0 \cdot PD_i, \quad \forall i = 1,\ldots, NILM \tag{43}$$

where, a_0 is a scalar, $0 < a_0 < 1$, which determines how much of the demand that could be made available for curtailment by the interruption load market participant, without causing any economic loss to itself.

Market Settlement: It is proposed that the interruptible load market settlement is a non-discriminating auction where all selected offers will be paid the same price (ISO pay-price) which is the highest accepted offer-price. The ISO pay-price can be included in the model as:

$$\rho \geq U_i \cdot \beta_i , \qquad \forall i = 1,\dots,NILM \tag{44}$$

The CRM as described above, is a mixed integer nonlinear programming problem and is solved using the GAMS/DICOPT solver [3].

6.2.3 Simulation Studies and Discussions

A. System Descriptions

The CIGRE-32 bus system, which approximately represents the Swedish network, is used for the simulation studies [4]. Details of the system are provided in Appendix 2.

B. Results and Discussions

The models described in Section 6.2.2 and the system described in Section 6.2.3.A are used to carry out a case study to examine the operation of the interruptible load market and its role in removing the congestion in the system. The model can be used for 24 hours in a day, however, in the present chapter, the results for only one single hour are reported. Table 6-1 shows the total demand interruption and the total payments by the ISO during peak load hour (19:00 hour).

Table 6-1: Load interruption and congestion management cost

at 19:00 hour	
Total load interruption (MWh)	177.7
Payment (US$)	4,442.5

Table 6-2 shows the lines which are identified as congested lines in the load flow model. Those line violations are largely influenced by load interruption at the buses whose congestion relief indices are substantially high as compared to those of other buses. For example, the line 4072-4071 has 37.5 MW overloaded, as identified by the model, the two buses 4072 and 2032 has significant high value of *CRI*, which means that interrupting the load at those buses will most likely reduce the congestion. The ISO would be able to remove those line violations by selecting the interruptible load offers in the interruptible load market. Those interruption are from buses 4072, 2032, *etc.*, as tabulated in Table 6-2.

Table 6-2: Line violations and demand interruptions

Line	Line flow Violation (MW)	Buses with significant *CRI*	ΔP (MW)
4072-4071	37.5	*4072*	19.5
		2032	12.6
4071-4012	62.4	*4021*	35.2
		1022	48.4
		1011	12.4
4012-4022	22.3	*4031*	10.2
		1012	13.4
4031-4041	0.4	*1044*	0.4
		1045	0.0
4022-4031	18.2	*4062*	6.8
		1013	18.8

6.3 Transmission Congestion Management: DC-Load Flow Method

6.3.1 Optimal Procurement of Interruptible Load Offers

Optimal interruptible load procurement will be based on an uniform price auction, *i.e.* all selected loads shall receive the same price (interruptible price, ρ), which is the highest accepted offer price. Figure 6-2 shows the working scheme of the proposed auction for interruptible load for relieving transmission congestion. The scheme can be executed in two steps as given below:

- *Load Flow Model* (LFM) - to be executed every hour to identify the congested lines.
- *Congestion Relief Model* (CRM) - a modified OPF, receiving interruptible load offers from customers and minimizing various objectives by the ISO while satisfying the congestion management objective.

It is to be noted that in order to create a fast and efficient congestion management tool as well as to demonstrate the method well, the models proposed in this paper are based on a dc load-flow formulation which assumes the system is lossless and has an unity voltage magnitude at all buses.

A. Load-flow model (LFM)

Load Flow Equations:

The basic load-flow equations, modified to include the power generation and demand separated according to those through bilateral contracts and those traded in the spot market, is as follows:

$$PG_{i,m} + PG_{i,b} - PD_{i,m} - PD_{i,b} = \sum_{j} B_{ij} \cdot \delta_j \qquad (45)$$

The simulation of bilateral contracts for generation and demand is presented in detail in Appendix 1.

The power flow on line i-j can be calculated as:

$$P_{ij} = -\left(\delta_i - \delta_j\right) \cdot B_{ij} \qquad (46)$$

Once the power flows on all transmission lines are calculated, they are compared with the respective power transfer limits $P_{ij}^{\max}$ of each line in order to identify the lines which are overloaded. If line(s) overload exits, necessary actions need to be taken, and accordingly the CRM (as will be described in Section 6.3.1.B), is executed. The LFM is a linear programming problem and is solved using the well-known solver XA in GAMS [3].

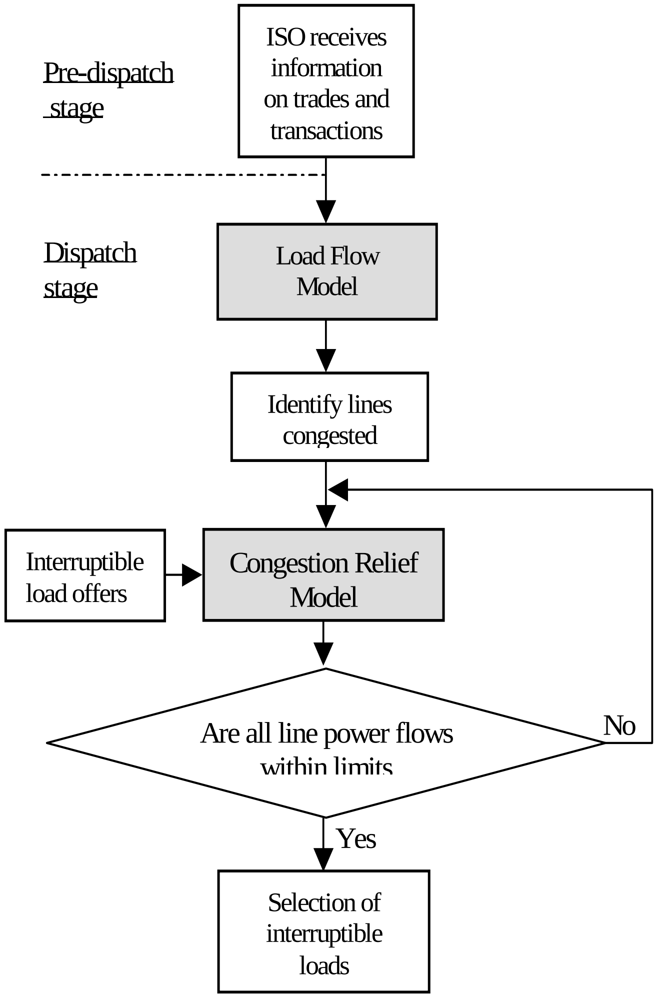

Figure 6-2: Schematic diagram of the proposed interruptible load auction model for congestion management

B. Congestion Relief Model (CRM)

Objective Function:

First of all, it is understandable that the ISO would not like to curtail demand at too many load buses, at the same time. One of the objectives of the ISO is therefore, to minimize the number of load buses at which interruption is called for, denoted by NILS. This objective can be expressed as in (47):

$$NILS = \sum_{i}^{NIL} U_i \tag{47}$$

In (47), U is a binary decision variable denoting the selection (U=1) or otherwise (U=0) of interruptible load at a bus, from the set of buses (*i = 1,…, NIL*) where customers are participating in the interruptible load market.

The other objective of the ISO would be to minimize the total power interruption invoked, denoted by PILS, and can be expressed as in (48):

$$PILS = \sum_{i}^{NIL} \Delta PD_i \tag{48}$$

The third objective of the ISO would be to find the optimal set of interruptible load contracts such that the total payment made to the loads is minimized. The total payment can be expressed as:

$$PAYMENT = \sum_{i} \Delta PD_i \cdot \rho \tag{49}$$

Note that ρ is the uniform interruptible load market price determined from the CRM and payable to all selected interruptible load offers invoked by the ISO.

As we can observe from the above, the ISO has three different objectives, normally of a contradictory nature, to satisfy different goals. However, the ISO would often desire to achieve all the three goals simultaneously. To this effect, we propose a 'compromise programming' approach that attains the 'best compromise' amongst different objectives. The three objectives above can now be incorporated into a 'compromise function' (50), which, when minimized, will represent the ISO's overall requirement of meeting all objectives at the same time:

$$J_{COMPRO} = \sqrt{\left(\frac{NILS}{NILS*}\right)^2 + \left(\frac{PILS}{PILS^*}\right)^2 + \left(\frac{PAYMENT}{PAYMENT^*}\right)^2} \tag{50}$$

In (50), NILS*, PILS*, and PAYMENT* are the respective optimal values, when minimized individually (Figure 6-3) [5]. It is to be noted that equal weights have been assigned for each component in (50), which however need not be necessarily so, in actual markets. The ISO may choose to have different *preferences* for the three objectives, depending on the contractual agreements between the ISO and the interruptible load participants as well as the market condition.

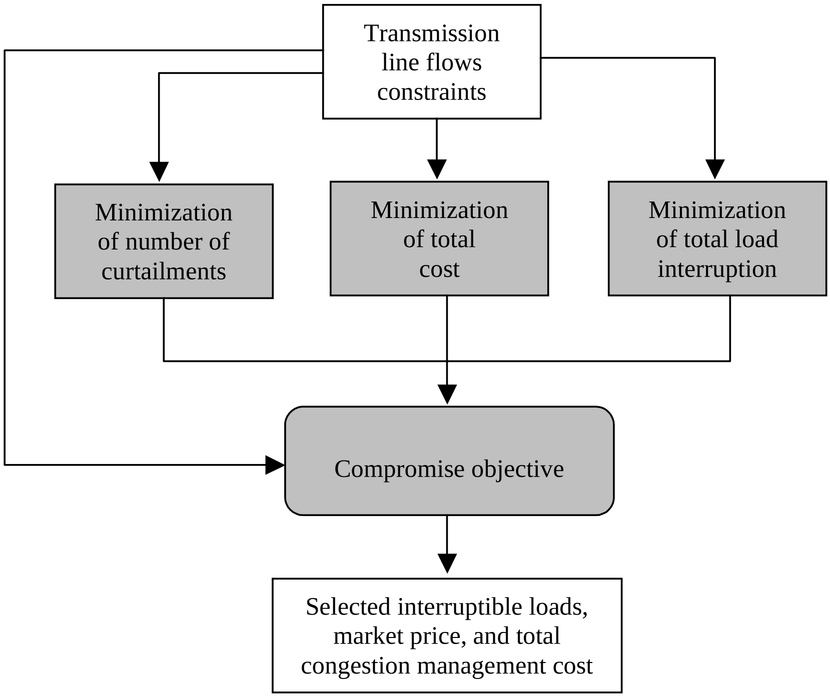

Figure 6-3: Formation of the Compromise Objective

The proposed "compromise" objective function (50) encompasses the basic issues that the ISO should incorporate in its decision making while procuring the interruptible load services. This objective function adequately represents the major concerns of the ISO that need to be addressed while invoking load interruption. It is to be observed that this objective function is somewhat different from the classical cost or social welfare (producer plus consumer surplus) based objective functions. Such an objective function is designed in order to avoid the pitfalls of using the classical objective function in these problems. For example, with a cost minimization function the ISO would end up with a stack of low-priced interruptible load offers irrespective of their location or impact on the system losses. On the other hand the proposed compromise function takes into account the number of interruptions, quantity of power interrupted and the payment to the ISO. This last term in effect does represent the social welfare under the assumption that the service providers offer their true cost / benefit functions.

Further, it is to be noted that the cost to the ISO is not the same as the cost to the society. The cost to the ISO is the payment burden that it has to undertake in order to procure these interruptible load services. On the other hand, cost to the society is the "congestion cost", *i.e. the cost of not having enough transfer capacity* as required from the unconstrained market settlement [6],[7].

Load Flow Equations: We also have the basic power flow equations at a bus *i*, similar to (4). To include the contribution of interruptible loads, it is re-written as:

$$PG_{i,m} + PG_{i,b} - PD_{i,m} - PD_{i,b} + \sum_{i}^{NIL} \Delta PD_i = \sum_{j} B_{ij} \cdot \delta_j \tag{51}$$

The power flow constraints: The power flow on line *i-j* has to be within its maximum limit:

$$P_{ij} \leq P_{ij}^{\max} \tag{52}$$

$P_{ij}^{\max}$ is the maximum transfer capacity of the line *i-j*.

Operating Reserve Constraints: This constraint ensures that a pre-specified and mandatory level of operating reserve is maintained by the ISO at all times. Since generator unit commitment decisions are beyond the ISO's purview, operating reserve from committed capacity may fall short at times and the ISO would need to make such provision from interruptible loads.

$$\sum_{i}^{NG} PG_i^{\max} \cdot UC_i - \sum_{i}^{NL} PD_i + \sum_{i}^{NIL} \Delta PD_i \geq RES \tag{53}$$

In (53), RES is the operating reserve requirement for the system.

Limit on Interruption: The actual interruption invoked by the ISO is constrained by the quantity offered by customers for interruption:

$$\Delta PD_i \leq \mu_i \cdot U_i, \qquad \forall i = 1, \ldots, NIL \tag{54}$$

Bidding for interruption: The quantity offered by an interruptible load market participant is limited by the total demand at its disposal.

$$\mu_i \leq a_{i0} \cdot PD_i, \qquad \forall i = 1, \ldots, NIL \tag{55}$$

In (55), a_{i0} is a scalar, $0<a_{i0}<1$, specifying the fraction of demand at a bus, that is offered in the interruption load auction.

Market Settlement: The interruptible load market is settled on second price uniform auction, where all selected offers are paid the same price ρ (interruptible load market price), which is the highest accepted offer price. The interruptible load market price is determined from the CRM using the following inequality constraint:

$$\rho \geq U_i \cdot \beta_i, \qquad \forall i = 1,\ldots,NIL \tag{56}$$

The CRM, as described above, is a mixed integer non-linear programming (MINLP) problem and is solved using the well-known DICOPT solver in GAMS [3]. Each of the three objectives are executed first with the constraints (equations 51-56), in order to find their optimums – PILS*, NILS* and PAYMENT*, respectively. Subsequently, the *Compromise* objective is constructed and solved considering the constraints (equations 51-56) in order to arrive at the compromise optimal solution while clearing all the congestion in the network.

6.3.2 System Studies

A. Design of cases for analysis

In order to simulate the interruptible load offers, to be submitted to the ISO, we use an uniform random number generator over a range of \$30/MWh to \$40/MWh, reflecting the peak-hour spot-market price, to generate offer prices (β_i) [8]. The bid quantity (μ_i) is generated using a fraction multiplier range for a_{i0} of 20% to 30% of total demand at a bus. However, it should be noted that these assumptions to generate offer prices and associated quantities is only illustrative at best and need not be the true in actual auction markets. Further, we do not consider strategic bidding (imperfect competition) issues in this work- wherein interruptible load participants' offer prices might vary as a function of the level of reserve available in the system [9].

We simulate cases where congestions exist on a number of transmission corridors. A "business as usual" case, with two lines overloaded, is first considered. Subsequently, in order to demonstrate the robustness of the method, several contingency cases (with *N-1* criterion) are also considered. The following simulation cases are considered in our analyses:

- Case A: "Business as Usual" (BAU)
- Case B: Contingency case with the transmission line *4042-4044* out-of-service
- Case C: Contingency case with the transmission line *4021-4042* out-of-service
- Case D: Contingency case with the generator *4041* out-of-service

B. *Results and discussions*

First of all, we identify the bottlenecks arising in the transmission system in different cases (Table 6-3). It is evident that lines *4022-4031* and *4031-4041*, which are the two main transmission corridors of power transmission from the north (where there is abundance of generation) to the south (the load centers) of the system, are overloaded in the BAU case. In Case B, when the transmission line *4042-4044* is out-of-service, it creates even more burden on the two lines *4022-4031* and *4031-4041* which are already overloaded, and additionally, line *4042-4043* also gets overloaded. In Cases C and D, the two lines *4022-4031* and *4031-4041* are more heavily loaded, although no new congested lines are created.

Table 6-3: Transmission line congestion in various cases

	Overload (MW)			
Lines Overloaded	Case-A	Case-B	Case-C	Case-D
4022 – 4031	727.95	760.30	1031.53	816.51
4031 – 4041	20.55	155.07	321.34	166.85
4042 – 4043	-	61.57	-	-
Total	748.50	976.94	1352.87	983.36

Table 6-4 shows the offer prices submitted by interruptible load participants. For the sake of uniformity of comparison, we assume that participants offer the same prices in all cases considered.

Table 6-4: Offer prices submitted by interruptible load participants

Bus No.	Offer price ($/MWh)	Bus No.	Offer price ($/MWh)
4072	31.18	*1044*	32.46
4071	33.14	*1045*	31.31
2032	32.84	*42*	39.33
1013	30.86	*41*	33.80
1012	31.03	*62*	37.83
1022	35.45	*63*	33.00
1043	37.92	*51*	31.25
1042	30.73	*47*	37.49
2031	33.89	*43*	30.69
1011	33.59	*46*	32.02
1041	32.43	*61*	30.05

Case A (Business as Usual)

Table 6-5 shows the selected interruptible load contracts by the ISO when each objective function is considered separately, *i.e.*, minimization of NILS (hereafter, Min of NILS), minimization of PILS (hereafter, Min of PILS) and minimization of PAYMENT (hereafter, Min of PAYMENT). Also shown are the optimal procurement decisions for minimization of the *compromise* function (hereafter, Min of COMPRO). Depending on the objective function considered, the CRM selects the optimal interruptible load contracts so as to alleviate the existing congestions on the two lines *4022-4031* and *4031-4041*. It also ensures that there is no new line congestion introduced because of the load interruption. The CRM also determines the market clearing price, which is the highest accepted offer price. We refer to the bus that has the highest accepted offer price as the *price-setter* bus. The *price-setter* bus varies with different objectives and is shown in Table 6-5 by the underlined, *i.e.*, *1043* in Min of PILS, *62* in Min of PILS, *1045* in Min of PAYMENT and in Min of COMPRO are the *price-setter* buses.

Table 6-5: Interruptible load contracts for Case A with different objectives

Min of NILS		Min of PILS		Min of PAYMENT		Min of COMPRO	
Bus	Interruption (MW)	Bus	Interruption (MW)	Bus	Interruption (MW)	Bus	Interruption (MW)
1043	109.70	*2032*	103.77	*1042*	133.98	***1045***	318.72
1044	323.49	*2031*	47.65	***1045***	318.72	*51*	373.77
51	373.77	*41*	271.85	*51*	373.77	*43*	237.36
43	424.51	***62***	127.33	*43*	101.44	*61*	221.86
		63	252.02	*61*	221.86		
		51	77.81				
		61	221.86				

Note: the underlined bus is the *price-setter* bus in each objective

Table 6-6 shows a summary of the number of contracts, total demand interruption, total payment for congestion management, as well as market clearing price in each of the four objectives considered for investigations in Case A.

Table 6-6: Summary results for Case A

Objective (Min of)	NILS	Interruption (MW)	Payment (k$)	Market Price ($/MWh)
NILS	4	1231.47	46.70	37.92
PILS	7	1102.31	41.70	37.83
PAYMENT	5	1149.78	35.99	31.31
COMPRO	4	1151.71	36.05	31.31

Figure 6-4 shows the plot of normalized values of the various objectives with respect to the COMPRO objective in Case A.

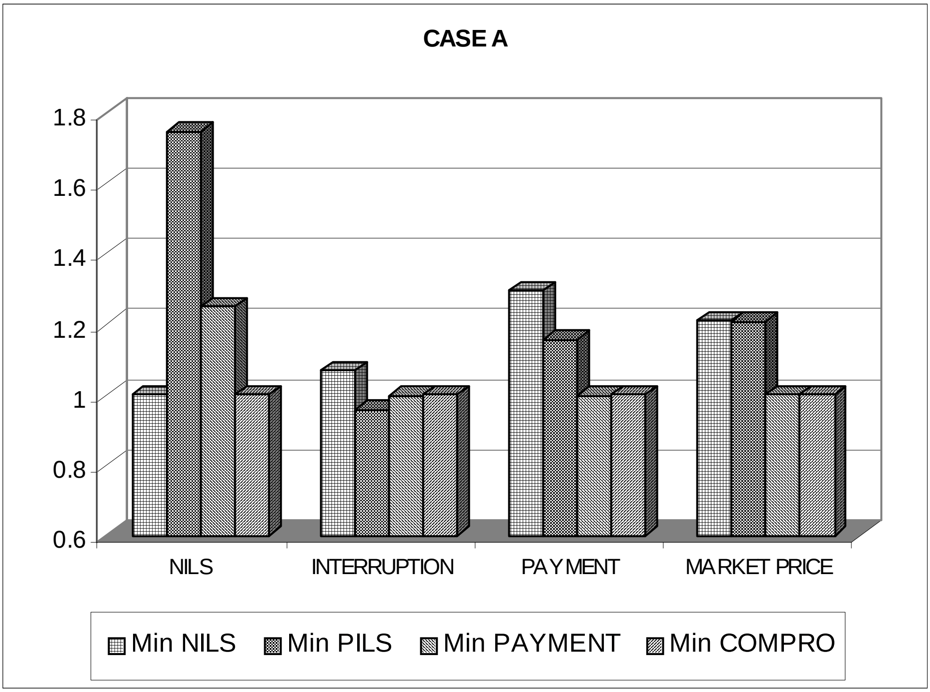

Figure 6-4: Normalized (with respect to COMPRO objective) NILS, interruption, payment, and clearing price of interruptible load auction considering different objectives in Case A

As can be seen from Figure 6-4 that if the ISO minimizes only NILS, it would need to contract the highest amount of interruptible load as well as pay the highest market price and hence would incur the highest total congestion management cost. Now, if the ISO chooses to minimize the total load interruption requirement, it has to contract the maximum number of interruptible buses, while the market price is little lower than with the previous. Since the amount of interruptible load is minimized the total payment will reduce significantly. If we now look at the third objective of the ISO, which is the minimization of payment, we will see that the price and total cost are the least in all objectives considered, while the amount of interruption is still higher than that of the Min of PILS case. The number of interruptible load contracts required would be higher than that in the case of Min of NILS. In the compromise solution, we can see that the market price is the same as in the case of Min of PAYMENT, the amount of total load interruption is almost the same as that of Min of PAYMENT case, while it has the number of contracts required as low as in the Min of NILS case. This could well justify a little increase in total cost as compared to that of Min of PAYMENT case.

Case B (Transmission line 4042-4044 out-of-service)

In Case B, when line *4042-4044* is out-of-service, there are three lines which are overloaded (see Table 6-3). It also means that more interruptible loads would be required to clear all the congestion as can be seen in Table 6-7. Similar to Case A, the *price-setter* bus changes with different objectives and is shown underlined, i.e., *1043* in Min of PILS, *62* in Min of PILS, *1045* in Min of PAYMENT and in Min of COMPRO.

Table 6-7: Interruptible load contracts for Case B with different objectives

Min of NILS		Min of PILS		Min of PAYMENT		Min of COMPRO	
Bus	Inter-ruption (MW)	Bus	Inter-ruption (MW)	Bus	Inter-ruption (MW)	Bus	Inter-ruption (MW)
1043	109.70	*2032*	103.76	*1042*	133.97	***1045***	318.72
1045	318.71	*2031*	47.65	***1045***	318.71	*51*	373.77
51	373.77	*41*	271.84	*51*	373.77	*43*	277.21
43	424.50	***62***	127.33	*43*	139.82	*61*	221.86
		63	252.02	*61*	221.86		
		51	119.27				
		61	221.86				

Note: the underlined bus is the *price-setter* bus in each objective

Table 6-8 shows a summary of the results of the number of contracts, total demand interruption, total payment for congestion management, as well as market clearing price in each of the four objectives considered for investigations in Case B.

Table 6-8: Summary results for Case B

Objective (Min of)	NILS	Interruption (MW)	Payment (k$)	Market Price ($/MWh)
NILS	4	1226.69	46.52	37.92
PILS	7	1143.78	43.27	37.83
PAYMENT	5	1188.16	37.20	31.31
COMPRO	4	1191.57	37.30	31.31

Figure 6-5 shows the plot of normalized values of the objectives with the reference values being that of Min of COMPRO objective.

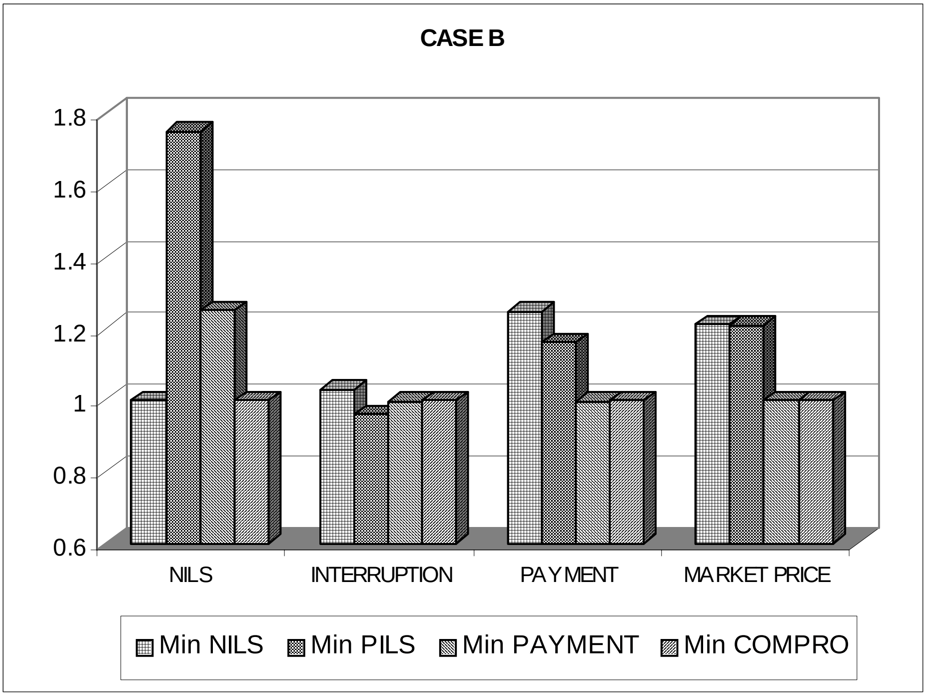

Figure 6-5: Normalized (with respect to COMPRO objective) NILS, interruption, payment, and clearing price of interruptible load auction considering different objectives in Case B

Similar to Case A, Figure 6-5 shows the same pattern in NILS, total interruption, total cost as well as market price. The *Compromise* objective would best satisfy all the objectives of the ISO at the same time. Total cost incurred and total demand interruption required in this contingency case is higher than those in the BAU.

Case C (Transmission line 4021-4042 out-of-service)

In Case C, when line 4021-4042 is out-of-service, no new line overload is introduced unlike in the previous case. However the amount of overload is much higher now in the two lines, which would requires more interruptible loads to be invoked to clear all the congestion (Table 6-9). The price-setters in Case C are now different from the two previous Cases, i.e., 2032 in Min of PILS, 62 in Min of PILS, 46 in Min of PAYMENT and in Min of COMPRO. The number of interruptible load contracts is also higher in this case as compared to the previous two cases.

Table 6-9: Interruptible load contracts for Case C with different objectives

Min of NILS		Min of PILS		Min of PAYMENT		Min of COMPRO	
Bus	Interruption (MW)	Bus	Interruption (MW)	Bus	Interruption (MW)	Bus	Interruption (MW)
<u>2032</u>	103.77	*2032*	103.77	*1042*	133.98	*1045*	318.72
1045	318.72	*2031*	47.65	*1045*	318.72	*51*	373.77
51	373.77	*1045*	65.33	*51*	373.77	*43*	258.39
43	424.51	*41*	271.85	*43*	424.51	***<u>46</u>***	315.21
46	315.21	***<u>62</u>***	127.34	***<u>46</u>***	14.67	*61*	221.86
		63	252.02	*61*	221.86		
		51	373.77				
		61	221.86				

<u>Note</u>: the underlined <u>bus</u> is the *price-setter* bus in each objective

Table 6-10 shows a summary of the results of the number of contracts, total demand interruption, total payment for congestion management, as well as market clearing price in each of the four objectives considered for investigations in Case C.

Table 6-10: Summary results for Case C

Objective (Min of)	NILS	Interruption (MW)	Payment (k$)	Market Price ($/MWh)
NILS	5	1535.97	50.44	32.84
PILS	8	1463.60	55.37	37.83
PAYMENT	6	1487.51	47.63	32.02
COMPRO	5	1487.95	47.64	32.02

Figure 6-6 shows the plot of normalized values of Table 6-10 with the reference values being that of Min of COMPRO objective.

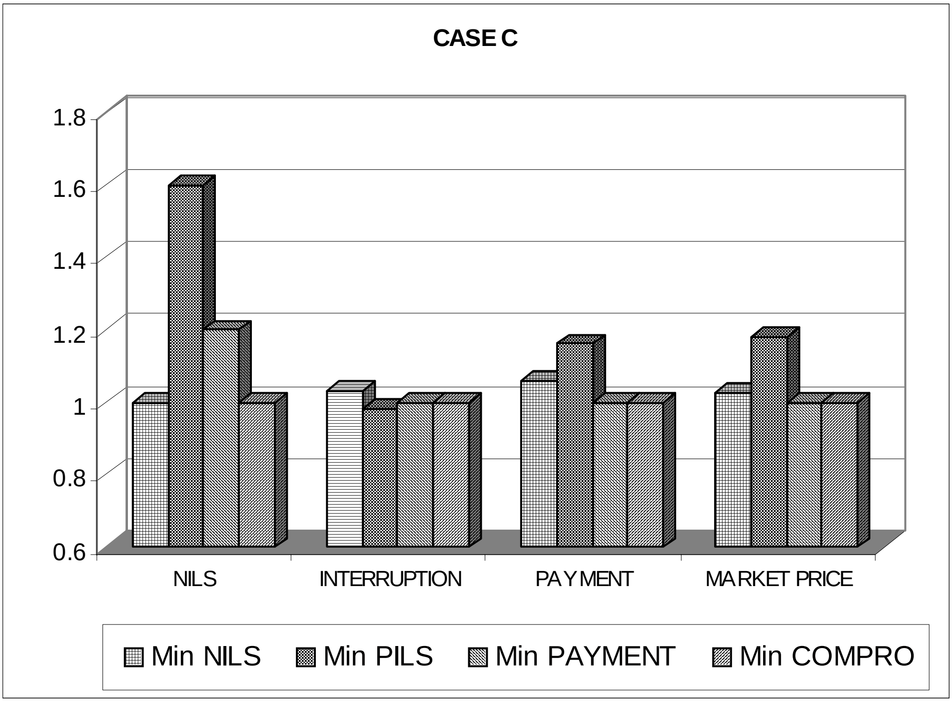

Figure 6-6: Normalized (with respect to COMPRO objective) NILS, interruption, payment and clearing price of interruptible load auction considering different objectives in Case C

Figure 6-6 shows the same pattern in NILS, total interruption, total payment and market price as compared to previous two cases. The Compromise objective would best satisfy all the objectives of the ISO at the same time. Total cost incurred and total demand interruption required in this contingency case is higher than those in the BAU case. It is interesting to note that the amount of demand contracted in Min of PAYMENT is almost the same as that of in Min of COMPRO, while the number of contracts in Min of COMPRO is smaller than that of Min of PAYMENT. As it stands, Min of COMPRO is naturally the best objective in Case C.

Case D (Generator 4041 out-of-service)

In Case D, when generator *4041* is out-of-service, no new line overloads are introduced. However the amount of overload is higher in this Case as compared to the BAU. It means that more interruptible loads would be required to clear all the congestions (Table 6-11). The *price-setter* buses in this Case are *1045* in Min of PILS, *62* in Min of PILS, *1045* in Min of PAYMENT and in Min of COMPRO.

Table 6-11: Interruptible load contracts for Case D with different objectives

Min of NILS		Min of PILS		Min of PAYMENT		Min of COMPRO	
Bus	Inter-ruption (MW)	Bus	Inter-ruption (MW)	Bus	Inter-ruption (MW)	Bus	Inter-ruption (MW)
1045	318.72	*2032*	103.77	*1042*	133.98	***1045***	318.72
51	373.77	*2031*	47.65	***1045***	318.72	*51*	373.77
43	424.51	*41*	271.85	*51*	373.77	*43*	380.48
61	221.86	***62***	127.34	*43*	244.56	*61*	221.86
		63	252.02	*61*	221.86		
		51	218.53				
		61	221.86				

Note: the underlined bus is the *price-setter* bus in each objective

Table 6-12 shows a summary of the results of the number of contracts, total demand interruption, total payment for congestion management, as well as market clearing price in each of the four objectives considered for investigations in Case D.

Table 6-12: Summary results for Case D

Objective (Min of)	NILS	Interruption (MW)	Payment (k$)	Market Price ($/MWh)
NILS	4	1338.86	41.91	31.31
PILS	7	1243.03	47.03	37.83
PAYMENT	5	1292.89	40.47	31.31
COMPRO	4	1294.83	40.54	31.31

Figure 6-7 shows the plot of normalized values of Table 6-12 with the reference values being that of Min of COMPRO objective.

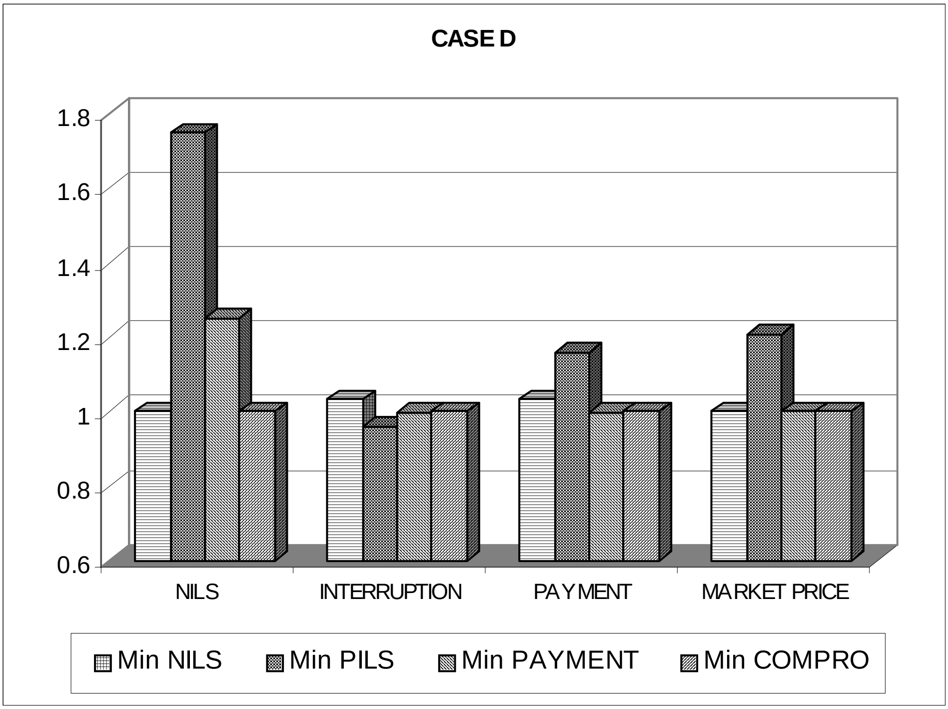

Figure 6-7: Normalized (with respect to COMPRO objective) NILS, interruption, payment, and clearing price of interruptible load auction considering different objectives in Case D

As can be seen, Figure 6-7 shows the same pattern in NILS, total interruption, total cost and market price as compared to previous Cases. The compromise objective would best satisfy all objectives of the ISO at the same time. It can be seen that the amount of demand contracted in the case of Min of PAYMENT is almost the same as that of in the case of Min of COMPRO, while the number of contracts in case of Min of COMPRO is smaller than that of Min of PAYMENT case. It is interesting to look at Table 9, the interruption required is shifting from the bus *1042* (in Min of PAYMENT) to the bus *43* (in Min of COMPRO), thereby reduces the number of interruptible contracts while sacrificing a little in PAYMENT. As it stands, Min of COMPRO is naturally the best objective in Case D.

6.4 Conclusions

The two proposed congestion management methods could specifically identify the bus locations where corrective measures need to be taken for removal of transmission bottlenecks in the system. An auction mechanism for interruptible loads has been designed and integrated with the Congestion Relief Models. The first method does not utilize the constraints on power flow, and hence in some cases, the model is not able to remove all transmission congestion. The second approach proposed, is based on a dc optimal power flow framework, and overcomes the drawback of the first approach. The N-1 contingency criterion has been taken into account to simulate various cases and hence examine the effectiveness of the proposed method. It has been shown that the method can assist the ISO to remove the overload from lines in both normal and contingency conditions in an optimal manner. It can therefore be concluded that with the proper contracting framework, interruptible load auction scheme should be an effective tool for congestion management of the ISO in the case of the dominant bilateral contracts market.

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CHAPTER 7*

OPTIMAL INVESTMENT IN RESERVE SERVICES

The first part of this chapter develops a framework for the determination of a long-term solution to the congestion management problem through "fast start-up" gas-turbine generators based on the traditional cost-benefit analysis. This involves a planning exercise to arrive at optimal location and size of gas-turbine generators in the system such that the total cost of investment and cost of congestion is minimized. A bus-wise cost-benefit analysis is carried out by solving iteratively a dc optimal power flow model. It is shown that the long-term investment decisions are dependent on the opportunity cost of gas-turbine generators with respect to the transmission capacity available and the associated congestion problem.

In the second part of this chapter a least-cost optimization model is presented that seeks investment plans for fast start-up gas-turbine generators in order to provide for reserve and congestion management services. Since in the first part transmission congestion was used in the objective function, but not as a hard constraint, we experienced the problem that congestion was not totally removed. In the other method power flow constraints are introduced to completely remove the transmission congestion. The model thus evolved is an integer programming model and provides the optimal location of gas-turbine generators so as to minimize total cost of investment plus the cost of unserved energy.

7.1 Introduction

In Chapter 6, we have proposed the development of an interruptible load service market to address the problem of managing transmission congestion in deregulated power systems. We have also discussed in a previous chapter the various methods- both technical and economic- that have been proposed by researchers to address the congestion management problem.

However we must note that electric power systems where transmission bottlenecks exist on a continuous basis require a long-term solution to the problem. In such cases, it is more a problem of insufficient available transmission capacity than mere congestion on a line that can be handled by a price-area

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* The work contained in this chapter will be published in the following paper:

L.A. Tuan, K. Bhattacharya and J. Daalder, "Optimal Investment in Reserve Services", *IEE Proceedings: Generation, Transmission and Distribution* (in review) separation or generation re-scheduling. In fact methods such as pricing, generation re-scheduling or even interruptible load invocation strategies, if used for addressing transmission capacity shortages, could introduce other inefficiencies in the system. The problem with these methods is that they may introduce the risk of increasing electricity prices due to the market power of local generators in the congested areas.

To provide the level of reliability that customers expect, power systems operate with a generation capacity margin, called reserve. The cost of maintaining this reserve margin is significant, and it is in the customer's best interest to minimize it [1]. The paper proposes that in the long-run, this can be achieved without sacrificing reliability by giving an incentive to the generating companies to improve the availability of their units. This incentive can be achieved by charging the cost of reserve to the generating companies on the basis of their contribution to the reserve requirements. A unit contribution to reserve needs increases with its size and with its record of unavailability.

Under deregulation, power plants can be built anywhere in the system, resulting in the imbalance between generation and transmission. Shortages of generation in some subregions result in bottle-necks within a system, raising reliability concern regarding sub-regional installed capacity requirement [2]. It is pointed out in [2] that there would be a need to determine locational requirement for both generation and transmission such that assistance to subregions under random generator outages is not restricted. The paper also presents optimization procedures to determine the adequacy and responsibility for locational generation and transmission.

In order to address the transmission capacity shortage and associated congestion problems, the installation of reserve gas-turbine generators that can be synchronized with the grid within a short time, is a feasible option. The installation of gas turbine generators at different buses will provide relief to the system in terms of transmission line overloads in case of contingencies. It will help the ISO manage the congestion while stabilizing the market in the congested areas.

This chapter consists of two main parts:

- The first part proposes a scheme for evaluation of long-term investments by the ISO on gas-turbine generators. The objective is to determine optimal location and size of gas-turbine generators that can effectively reduce congestion in the system at minimum cost and in the long-run provide a solution to transmission bottlenecks. The cost defined here involves the cost of installing gas-turbine generators and the *opportunity* *cost* of not having such provisions (OCG). OCG denotes how much cost the system would incur because of transmission congestion if the generator is not present. The optimal selection of location and size for gas-turbine generators largely depend on a proper estimation of the OCG. Sensitivity analysis has been carried out to capture these dependencies. A heuristic algorithm has been proposed to carry out a bus-wise cost-benefit analysis to ensure that the selection of gas-turbine generators is cost-effective in terms of transmission congestion relief, in the long-run.

- The second part, on the other hand, proposes a least-cost optimization model for evaluation of long-term investments on gas-turbine generators to provide for reserve and congestion management ancillary services. The socially-desirable objective of minimizing the total cost of installation and operation and cost of *unserved energy* is used. Unlike in the first part, the transmission constraints are imposed explicitly, therefore, all the congestion in the network can be removed with the help of additional reserve capacity.

7.2 Investment Plan Decision Making Framework: Cost-Benefit Analysis Method

7.2.1 DC-OPF Model

The basic system analysis is carried out using a modified dc-OPF model to determine the investment decision on gas-turbine generators. A dc-OPF is considered here in order to reduce the computational burden significantly without affecting this basic principle of the decision making framework or without any loss of generality. The objective is minimization of total line violation cost plus the investment cost of gas-turbine generators (in terms of hourly investment cost plus operating cost).

Objective Function: The objective function is designed to represent the ISO’s total cost of installing and operating the gas-turbine generators and the cost associated with congestion. The later component (VC) is basically the opportunity cost of not-installing the gas-turbine generator and is termed as congestion cost. It simply implies how much it would cost the system per MW overload without the presence of a gas turbine generator.

$$OBJ = \sum_{i} GTC_i \cdot GT_i + \sum_{i}\sum_{j} PVIOL_{ij} \cdot VC \tag{1}$$

GTC_i is the hourly cost of installing a gas-turbine generator at bus *i*, *GT_i* is the decision variable on selection of gas-turbine and *$PVIOL_{ij}$* is the line-flow exceeding the transfer capacity limit of the line *i-j*:

$$PVIOL_{ij} = P_{ij} - P_{ij}^{\max} \quad \forall P_{ij} > P_{ij}^{\max} \tag{2}$$

Load Flow Equations: We have the basic dc power flow equations for bus *i*:

$$P_{g_i} - P_{d_i} = \sum_{j} B_{ij} \cdot \delta_j \tag{3}$$

To include the power generation and demand of bilateral contracts and power traded in the spot market, (3) can be rewritten as:

$$PG_{i,m} + PG_{i,b} - PD_{i,m} - PD_{i,b} + GT_i = \sum_{j} B_{ij} \cdot \delta_j \tag{4}$$

The power flow one the line *i-j* between the bus *i* and bus *j* can be calculated as:

$$P_{ij} = -\left(\delta_i - \delta_j\right) \cdot B_{ij} \tag{5}$$

Simulation of Bilateral Contracts: Appendix 1 provides details on how the bilateral contracts are constructed and included in the simulation model.

Operating Reserve Constraints: This constraint ensures that a pre-specified and mandatory minimum level of operating reserve is maintained at all time.

$$\sum_{i}^{NG} PG_i^{\max} \cdot UC_i - \sum_{i}^{NL} PD_i + \sum_{i} GT_i \geq RES \tag{6}$$

The dc-OPF model as described above is a non-linear programming problem and is solved using a well-known GAMS/MINOS solver [3]. It is to be noted here that the investment planning model would generally involve an exercise over the long-term planning horizon, however, given the non-linear nature of our problem, we simplify the problem by calculating the "hourly cost" of the gas-turbine investment over its economic life (assumed 15 years) in order to reduce the time horizon to 1 hour in the present study.

7.2.2 Cost-Benefit Analysis

In order to analyze the cost-effectiveness of the selected generator from the above model a cost-benefit analysis is proposed to determine the selected units that are cost-effective and in what size. The outcome of the cost-benefit analysis is incorporated in the dc-OPF in an iterative way to arrive at the optimal solution. Figure 7-1 and the following step-by-step procedure describe the proposed algorithm for optimal selection of gas-turbine generators:

Step 1: Run dc-OPF model for 24 hours considering the hourly load demand at each bus. All buses are considered as a possible candidate for gas-turbine generator installation and constitute the initial *selection set*. The solution provides the preliminary selection of gas turbine generators at different buses in the system.

Step 2: With estimated sizes of gas turbine generators, determine the standard size of the generator to be installed at each bus *i* and the total cost involved, considering a 15-year life.

Step 3: The marginal benefit from installing the gas turbine generator on bus *i* is calculated by removing the generator and re-running the dc-OPF while other things remain unchanged. The difference in the objective function is the marginal benefit from the generator installed on bus *i*.

Step 4: Calculate the benefit-to-cost-ratio *(BCR)* for all selected generators. If *BCR* for the generator on bus *i* exceeds unity, then that generator is selected. If the *BCR* is less than unity, consider a generator of lower capacity and recalculate the *BCR* to check if it could yield a *BCR* greater than unity. Otherwise, the generator at this bus is rejected.

Step 5: Remove all rejected generators and corresponding buses from the *selection set* and go to Step 1. Go to Step 6 only when all buses have *BCRs* greater than unity.

Step 6: Run dc-OPF considering only selected bus generators. If this gives a feasible solution, the selection is final.

Step 7: If Step 6 results in violation of any constraint, additional gas turbine generators are included in succession at buses, where they were previously rejected in Step 4, in decreasing order of their *BCRs* until a feasible solution is reached.

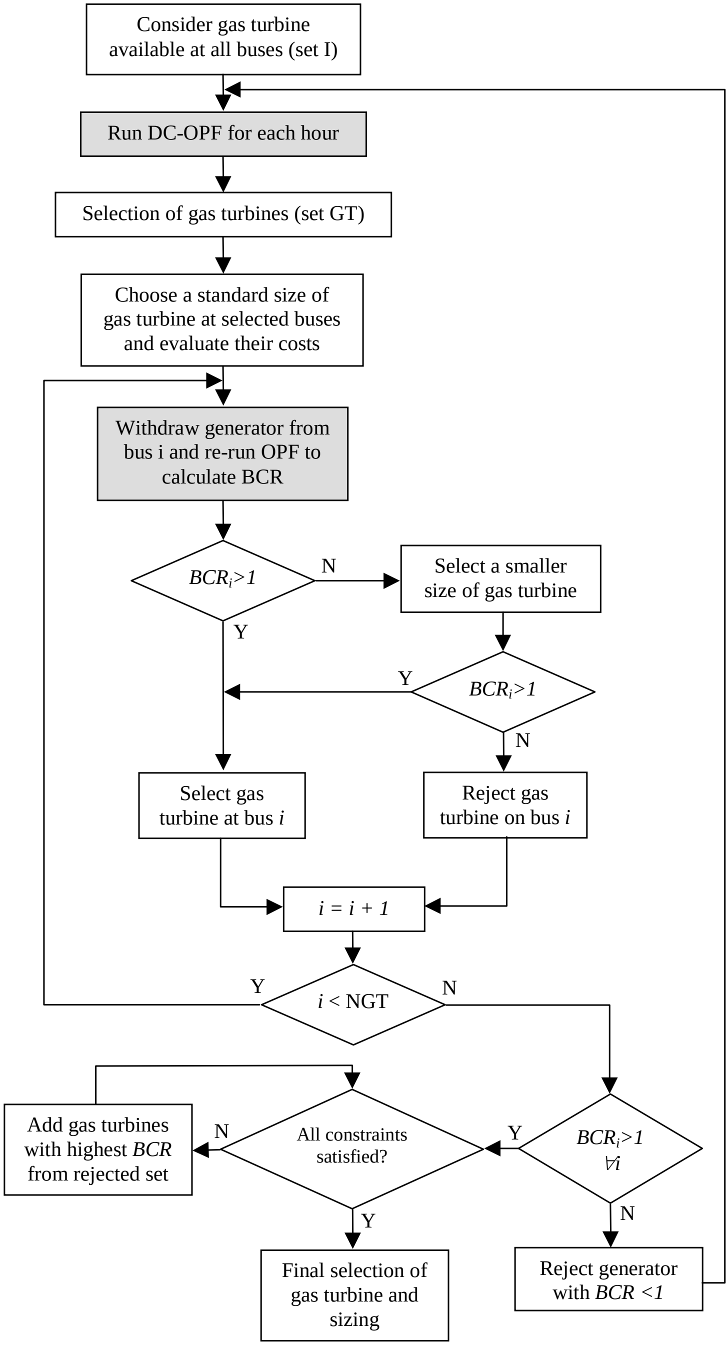

Figure 7-1: Scheme for optimal location and sizing of gas-turbine generators

7.3 Results and Discussions

7.3.1 Techno-Economic Analysis

The CIGRE-32 bus system, which approximately represents the Swedish network, is used for the simulation studies [4]. Details of the system are provided in Appendix 2.

The hourly load variation at a bus is accounted for by applying a load scaling factor (LSF) at each hour. The load at each hour *h* will be calculated by:

$$PD_i^h = PD_i \cdot LSF^h \qquad (7)$$

To begin with, one needs to work out a techno-economic analysis of gas-turbine generator using the unit's operating/name-plate ratings. Table 7-1 provides the techno-economic data of a typical gas turbine generator to be considered as a "candidate" at different buses in the system [5].

Table 7-1: Techno-economic data of a typical gas-turbine generator

Data	Unit	
Size *(Cap)*	MW	100.00
Capacity cost *(CC)*	$/kW	395.00
Fuel type	Diesel oil	-
Net heat rate *(HR)*	Btu/kWh	11,785.00
Fixed O&M cost *(FOM)*	$/kW-yr	11.17
Variable O&M cost *(VOM)*	$/MWh	5.00
Economic life *(EL)*	Years	15.00
Fuel cost *(FC)*	$/MBtu	6.00
Interest rate *(r)*	-	0.10

Table 7-2 presents the investment and operational cost analysis of the candidate gas-turbine generator. The candidate gas turbine generators of 100 MW capacity are considered to be available for investment at all buses. A capital cost of 400 $/kW installed capacity, variable operating cost of 5 $/kWh and fixed operating cost of 11.17 $/kW-year are considered for the study. Assuming a 15 year economic life, the total cost per MWh would be $131.8.

7.3.2 Location and Sizing of Gas Turbine Generators

The method described in Section 7.2 is used to carry out a case-study to examine the role of gas turbine generators in providing congestion relief to the system in the long-run. In this case study, only one loading condition (during peak load hour at 19:00 o'clock) with LSF = 1.0 is considered.

Table 7-2: Economic costs of a gas-turbine generator

Cost component	Unit	Calculation Formula	Result
Plant capacity factor *(PCF)*	%	-	30
Operating hours *(OH)*	hour	= 8760**PCF*	2,628.00
Capital recovery factor[1] *CRF* (10%, 15 years)	-	-	0.13
Levelizing factor *(LF)*[2] 6% price escalation	-	-	1.40
Annual fuel cost *(AFC)*	M$/year	= *Cap*OH*HR*FC*LF*	26.04
Annual fixed O&M Cost *(AFOM)*	M$/year	= *Cap*FOM*LF*	1.57
Variable O&M cost *(AVOM)*	M$/year	= *Cap*OH*VOM*LF*	1.84
Annual capacity cost *(ACC)*	M$/year	= *Cap*CC*CRF*	5.19
Total annual cost *(TAC)*	M$/year	= A*FC+AFOM+AVOM +ACC*	34.64
Hourly cost *(HC)*	$/hour	= *TAC/OH*	13,179.57
Unit cost *(GTC)*	$/MWh	= *HC/Cap*	131.80

Table 7-3 shows the selection of gas turbine generators at different buses in the network during 19:00 hour. As can be seen, after the first dc-OPF run (base case), six generators are selected by the model. However, only those at bus 4062 and 1041 have *BCR* greater than unity. As described in Section 7.2.2, in order to calculate the marginal benefit resulting from generators at bus *i*, the dc-OPF is re-

[1] CRF is used to find the equivalent value of future annuity given the present investment equivalent: $CRF = \frac{r(r+1)^n}{(r+1)^n - 1}$ with r and n being the interest rate and number of years, respectively. More details can be found in [5].

[2] LF is used to calculate the uniform levelized annual equivalent of an inflation series: $LF = \frac{\left[1 - \left(\frac{1+a}{1+r}\right)^n\right]}{r-a} \cdot CRF$ with a being the annual inflation rate.

run iteratively without a gas turbine generator at bus *i* selected in the previous dc-OPF run. However, in the subsequent OPF run, a new set of gas turbine generators is selected instead with different *BCR*. The dc-OPF has to be solved iteratively until the convergence at final solution when all selected gas turbines have *BCR* greater than unity (4062, 1041, 1045, 4045).

Table 7-3: Selected gas turbine generators (GTGs)

Iteration	Initial choice of *GTGs* at bus	Buses with BCR>1	Buses rejected
1	*4041*	*4062*	*4041*
	4062	*1041*	*4063*
	4063		*4051*
	4051		*1043*
	1043		*1042*
	1042		*4044*
	4044		*4061*
	4061		
	1041		
2	*4062*	*4062*	*4072*
	4072	*1041*	*4012*
	4012	*1045*	*4021*
	1045		*42*
	4021		*62*
	42		
	62		
3	*4062*	***4062***	*None*
	1041	***1041***	
	1045	***1045***	
	4045	***4045***	

7.3.3 Evaluation of Network Support by Gas-Turbine Generators

An index to quantify total transmission system congestion, Congestion Index *(CI)* [6], is used, which indicates the contribution of the gas-turbine generator to providing congestion relief**:**

$$CI = \sqrt{0.5 \cdot \sum_{i,j} \left(P_{ij} - P_{ij}^{\max}\right)^2 / NT} \qquad \forall P_{ij} > P_{ij}^{\max} \tag{8}$$

where, NT is the number of transmission lines.

Figure 7-2 shows the *CI* over a 24 hours time period in the system with and without the support of gas turbine generators. As can be seen, the installation of gas turbines has provided substantial support to improve network loading condition, especially during the peak hour (19:00 hours).

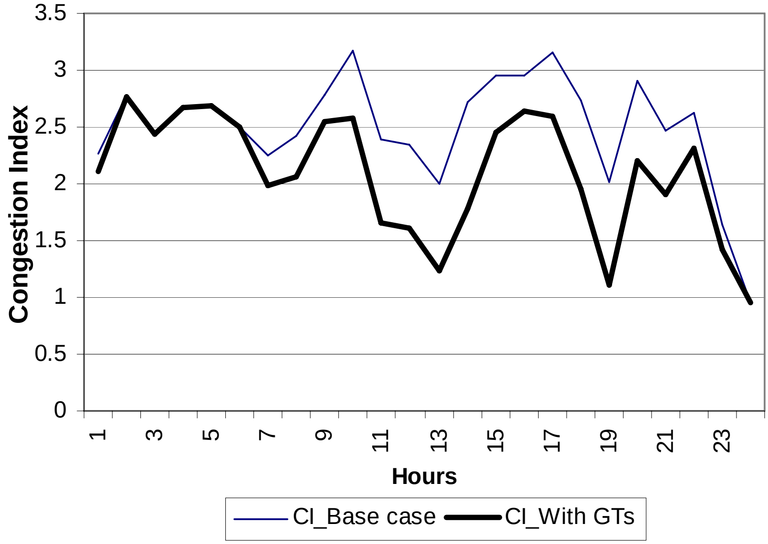

Figure 7-2: Congestion Index

In case of very high load (LSF = 1.6), the system experiences a condition of "energy not supplied". Without the installation of gas-turbine generators, the total energy not served during this hour is about 4000 MWh. As can be seen in Table 7-4, if the gas turbine generators are readily installed, it would otherwise reduce the total energy not served by almost 10%.

Table 7-4: Energy-not-served (MWh)

Bus	LSF=1.6 without GTGs	LSF=1.6 with GTGs
4041	173.0	176.3
4063	346.5	274.5
4043	671.4	701.3
4045	784.8	505.1
4046	495.7	486.4
4061	408.3	408.3
1041	491.3	391.3
1044	242.6	259.8
62	8.2	0.0
51	456.8	475.3
Total	4078.6	3678.3

However, it can be observed that the proposed model fails to remove all congestion from the transmission system. This is because the model seeks to minimize the total cost of investment and transmission violations. If the violation cost (VC) is accorded a very high weight in comparison to the investment costs, transmission congestion can be further reduced to a certain extent.

In the next section we propose a new scheme that succeeds in arriving at optimal investment plans while also removing congestion completely.

7.4 Investment Plan Decision Making Framework: Least-Cost Planning Method

7.4.1 Model Formulation

Objective Function: The socially desirable objective is to minimize the total cost of capacity and operation cost of gas-turbine generators and the cost associated with the energy not served.

$$OBJ = \sum_i GTC_i^{CAP} \cdot GT_i \cdot UG_i + \sum GTC_i^{OM} \cdot PGT_i \cdot UG_i + \sum_i UE_i \cdot UEC \tag{9}$$

In (9), GTC_i^{CAP} is the capacity cost while GTC_i^{OM} is the operation cost of gas-turbine generator i; UG_i is the binary (1/0) decision variable denoting selection (or not) of the gas-turbine generator; PGT_i is the power generated by gas-turbine generator i; UEC is the cost of unserved energy which is assumed to be \$320/MWh [7].

Load Flow Equations: We have the basic dc power flow equations for bus i:

$$PG_i - PD_i = \sum_j B_{ij} \cdot \delta_j \tag{10}$$

To include the power generation and demand of bilateral contracts and power traded in the spot market, and the generation from gas-turbine generators, (10) can be rewritten as:

$$PG_{i,m} + PG_{i,b} - PD_{i,m} - PD_{i,b} + UG_i \cdot PGT_i = \sum_j B_{ij} \cdot \delta_j \tag{11}$$

Constraint on Power Flow: The power flow one the line i-j between the bus i and bus j should be within its maximum limit.

$$P_{ij} \le P_{ij}^{\max} \tag{12}$$

$P_{ij}^{\max}$ is the maximum transfer capacity of the line i-j,

P_{ij} can be calculated by: $P_{ij} = -(\delta_i - \delta_j) \cdot B_{ij}$ (13)

Simulation of Bilateral Contracts: Appendix 1 provides details on how the bilateral contracts are constructed and included in the simulation model.

Operating Reserve Constraints: This constraint ensures that a pre-specified and mandatory minimum level of operating reserve is maintained at all time.

$$\sum_i^{NG} PG_i^{\max} \cdot UC_i - \sum_i^{NL} PD_i + \sum_i GT_i \cdot UG_i \ge RES \tag{14}$$

Constraints on Maximum Total Capacity of Gas-turbine Generators:

$$\sum_i GT_i \cdot UG_i \le TGT^{\max} \tag{15}$$

Installed capacity limit: Power generated from gas-turbine generator must be less than its maximum capacity:

$$PGT_i \le GT_i \qquad (16)$$

The dc-OPF model as described above is a mixed-integer linear programming problem and is solved using a well-known GAMS/XA solver [3].

7.4.2 Least-Cost Selection of Gas Turbine Generators

The model described in Section 7.4.1 is used to carry out a case-study to examine the role of the gas turbine generator in providing reserve services and congestion relief services to the system in the long-run. Table 7-5 presents the selection of gas-turbine generators (of 100 MW unit-size) at different buses in the system. The selection ensures that there is no congestion in the network and the reserve level is higher than (or equal to) the required level.

Table 7-5: Selected generators and their impact on transmission congestion

Selection of gas-turbine generators	Transmission Line	Line overload, MW: Without gas-turbines generators	Line overload, MW: With gas-turbines generators
4031, 4041, 2032, 1043, 1042, 4032, 4061, 2031, 1044, 41	4011-4021	165	-
	4012-4022	84	-
	4031-4041	788	-
	4031-4032	136	-
	4022-4031	1675	-
	4044-4045	130	-
	4044-1044	391	-
	Total overload	3368	-

Comparing the above with the results reported in Table 7-3, it is seen that the investment in the present case is significantly higher. In the previous case a total of 400 MW of gas-turbine capacity was selected for installation which was able to reduce the congestion to some extent, but not completely. In the present case, a total installation of 1000 MW can completely remove all transmission bottlenecks in the long-term.

7.5 Concluding Remarks

This chapter presents a method to evaluate long-term investment decisions on gas turbine generator allocation and sizing for the congestion management purpose. The chapter proposes that the ISO would be the responsible party to carry out the analysis and investment in order to have the available tool to support system operation. Network congestion is modelled and incorporated in the objective function of the model, not as a separate constraint. Therefore, the network congestion may not be removed completely in all cases. However, simulation results obtained in case studies have shown that the network overloading can be greatly reduced with support of the gas turbines at the selected buses. The choice of the value of cost associated with network congestion is found to have large influence on the selection and sizing of the gas turbine, hence the network overloading relief is provided. This chapter also attempts to provide an alternative method to evaluate long-term investment decisions on gas-turbine generator location and sizing to provide for reserve and congestion management ancillary reserve based on least-cost planning exercises. The method proposed could overcome the drawback of the previous method, which could help completely remove the congestion in all cases.

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CHAPTER 8

CONCLUSIONS AND FUTURE WORK

8.1 Conclusions

Since the last decade or more, the electric power industry has been undergoing a vast process of reform mainly involving a transition from natural monopolies with centralized planning, to market based structures that are subject to competition. It has been generally claimed that deregulation would improve the efficiency of electric power supply as a whole and thereby benefit consumers. However, it can be noted that competition has imposed new challenges to the operation of the electric power system, in terms of reliability and security issues. The ISO is entrusted with the responsibility of keeping the system "healthy" while facilitating bilateral and spot market transactions by procuring various ancillary services, such as, operating and emergency reserves, reactive power support and black start capability, among others.

In this thesis an attempt is made to examine the various issues related to interruptible load and how these could be integrated within the concept of system ancillary services and be managed by the ISO so as to improve the margins of security, especially during times of contingencies and transmission congestion.

To this effect, the thesis has comprehensively discussed and compared the available methods for management of interruptible load from the published research literature as well as real utility practices in this area. From this survey, it is concluded that interruptible load management has a potential for providing additional reserves with the net effect being as good as supply-side generation sources at lower costs.

The thesis further proposes a competitive market for interruptible load customers wherein they can offer to reduce a part of their demand, as an ancillary service provision, to be procured by the ISO. The operational objective of the market would be to minimize the total ILM procurement costs while satisfying the system operational constraints. It is shown that an interruptible load market can help the ISO maintain the operating reserves during peak load periods. Econometric analysis reveals that a close relationship exits between the reserve level and amount of interruptible load service invoked. It was also found that at certain buses, market power may exist with the loads, and that could lead to unwanted inefficiencies in the market. Investing in generation capacity at such buses can mitigate this.

It can be concluded that functioning of this interruptible load market would considerably help the ISO to maintain the system operating reserves by reducing the overall system demand during the peak load hours as well as in times of emergency. It is, therefore, very important to note that a proper contracting framework to attract customer participation, especially the large industrial customers, would enable the interruptible load market to function well.

Transmission congestion management is an essential and important task in the operation of an electric power system. The thesis has provided a detailed review of congestion management methods available in the research literature as well as in utility practice, one of which is the method using the demand-side resources. It is therefore desirable to investigate the role of interruptible loads, in addition to its utmost objective of peak load reduction, in transmission congestion relief. To this effect, the thesis has examined the possibility of an interruptible load market in providing transmission congestion relief.

Two approaches for procurement of interruptible load services by the ISO for transmission congestion management were developed. The first approach is based on an AC optimal power flow framework, which can be used for the real-time selection of interruptible load offers while satisfying the congestion management objective. The approach captures the “relief ability” of a load with respect to a certain transmission line through the important *congestion relief index.* The first method does not utilize the constraints on power flow, and hence in some cases, the model is not able to remove all transmission congestion. The second approach proposed, is based on a dc optimal power flow framework, and overcomes the drawback of the first approach. The proposed congestion management scheme using interruptible loads can specifically identify load buses where corrective measures are needed for relieving congestion on a particular transmission corridor. The N-1 contingency criterion has been taken into account to simulate various cases and hence examine the effectiveness of the proposed method. It has been shown that the method can assist the ISO to remove the overload from lines in both normal and contingency conditions in an optimal manner.

While examining the role of interruptible load in providing for congestion management, it is also necessary to arrive at long-term solutions to persistent congestions, i.e., a bottle-neck in the system. This calls for investment in reserve generation sources at strategic locations in the system in order to provide for congestion relief efficiently. A comprehensive cost-benefit analysis based heuristic method and a least-cost optimization based capacity planning exercise is undertaken to determine the long-term investment needs for fast start-up generators that can alleviate transmission bottlenecks and provide operating reserves.

8.2 Scope for Future Work

As mentioned earlier, it is very important to have the demand-side participation in the electricity market, i.e., the spot market, so as to improve the economic efficiency of the existing electricity market and limit the exercise of market power of the generators, especially the large ones, in the market. This thesis has established an ancillary service market for interruptible load customers where there is only one single buyer, the independent system operator, for their services. Such a market is termed as *monopsony*. Some of the future research directions with regard to interruptible load markets would be:

- to study the price-elasticity of the demand-side, since it will help the ISO to predict the likely demand level in case of rocketing electricity prices.
- to consider the recovery characteristics of customer loads after interruption, since, neglecting this may over-estimate the benefits of interruptible load management program.
- to study the market power of the generators in the electricity markets and find out the possible solutions to mitigate these, one of which would be through interruptible load participation in the electricity market.

APPENDICES

1 Modeling Bilateral Contracts

In bilateral contract dominated markets, the generating companies can enter into direct contracts with customers that can be days, weeks, or even months in advance. In order to appropriately simulate such kind of energy contracts/transactions, a system of linear-equations is used denoting the linkages between various parties involved. Bilateral contracts simulated must adhere to the two basic rules:

i) The sum of all contracts entered into, by a customer, equates the total demand of the said customer:

$$\sum_j PGcon_{i,j} = PD_{i,b}, \quad \forall i = 1,..., NL;\ j = 1,..., NG \tag{1}$$

Where: $PGcon_{i,j}$ is the contracted demand (MW) matrix of a load bus *i* to be provided by a generator *j*.

ii) The sum of all contracts entered into by one generator, equals the contracted generation of the said generator. Accordingly we have:

$$\sum_i PGcon_{i,j} = PG_{j,b} \quad \forall i = 1,..., NL;\ j = 1,..., NG \tag{2}$$

Note that in (1), although we show that $j=1, \ldots, NG$; in a practical system, not all generators may have a bilateral contract with a load at bus *i*. In such case, the appropriate elements of the *PGcon* matrix will be zero. The same applies to (2) where not all loads $i=1, \ldots, NL$; will actually have a bilateral contract with generator *j*. In such case, the appropriate *PGcon* matrix elements will be zero.

Further more, the amount of generation from a generator *j* scheduled for bilateral contracts is within a certain range from its maximum generating capacity:

$$P_j^{\max}.UC_j.a_0 \le \sum_i PGcon_{i,j} \le P_j^{\max}.UC_j.a_1, \quad \forall i = 1,..., NL;\ j = 1,..., NG \tag{3}$$

Note here that we, however, have not considered the maximum allowable amount of energy transaction between a load *i* and generator *j*, due to the unavailability of data.

2 CIGRE 32-Bus System

The Swedish 32-bus test system [1], as shown in Figure A-1, is used in the thesis for different case studies performed in Chapters 4, 6 and 7.

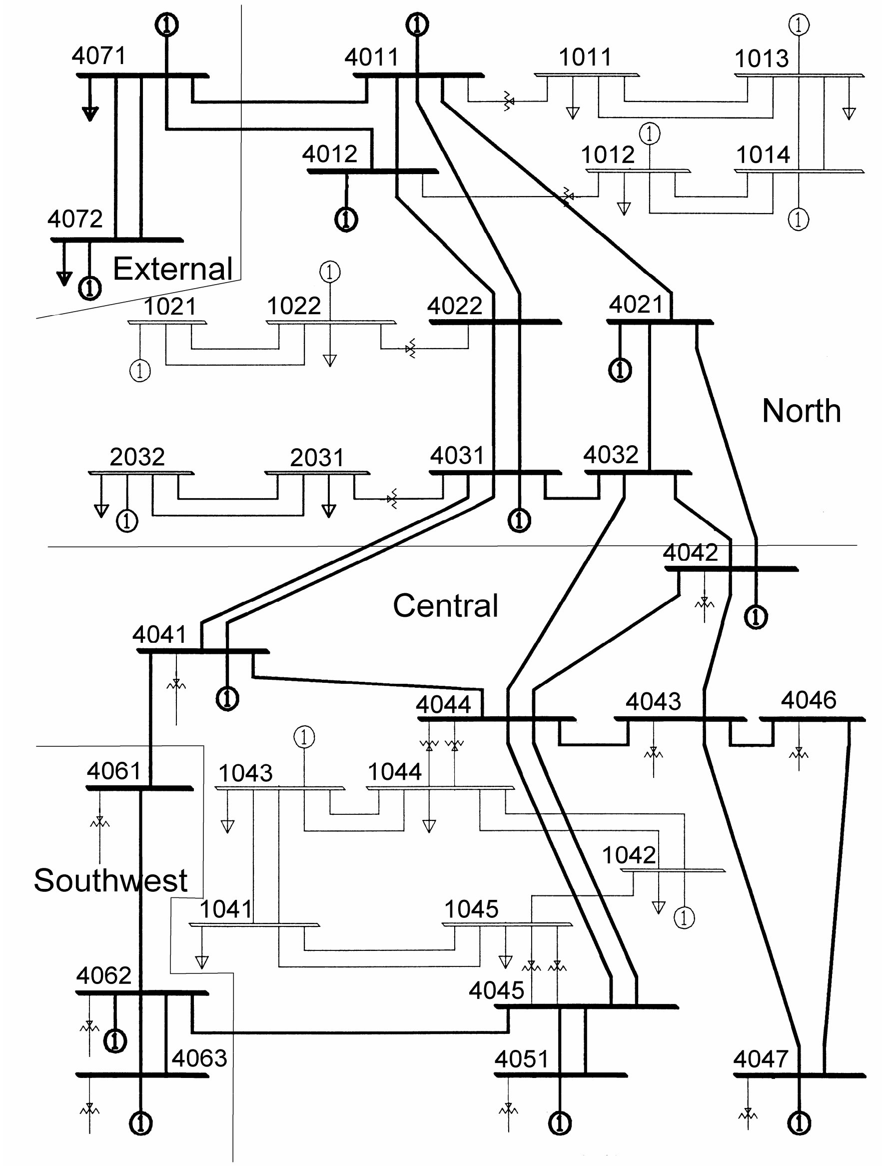

Figure A-1: CIGRE 32-Bus Test System Network Configuration

Note that load buses which are represented by 2-digit numbers (XX) are not shown in this figure, they are connected to the 400 kV buses (i.e., buses 40XX) through the 400/130 kV transformers. For example, bus 46 is connected with bus 4046 and so on.

The system can be divided into 4 main areas:

- *North:* mostly consists of hydro power plants and some load centers.
- *Central*: consists of a large amount of load and large thermal power plants
- *Southwest*: consists of some thermal power plants and some load
- *External*: connects to the North, it has a mix of generation and load

There are 19 generator buses and 21 load buses in the system. The bus #4011 is considered as the slack bus. The main power transfer is from "north" to "central". The main transmission system is designed for 400 kV. There are also regional systems at the voltage levels of 220 kV and 130 kV. The generators and the loads in the system are simulated to participate in the bilateral contracts market as well as the spot market. The simulation of the bilateral contract market is presented in the following section. The detailed data of generator buses in the system is provided in Table A-1. The load data is presented in Table A-2.

Table A-1: Generators data

Bus	P_{max} MW	Q_{max} MVAr	PD MW	QD MVAr	Q_{Sh} MVAr	Voltage level kV
4072	4500	1000	2000	500	-	400
4071	500	250	300	100	-400	400
4011	1000	500	-	-	-	400
4012	800	400	-	-	-100	400
4021	300	150	-	-	-	400
4031	350	175	-	-	-	400
4042	700	350	-	-	-	400
4041	300	300	-	-	200	400
4062	600	300	-	-	-	400
4063	1200	600	-	-	-	400
4051	700	350	-	-	100	400
4047	1200	600	-	-	-	400
2032	850	425	200	50	-	220
1013	600	300	100	40	-	130
1012	800	400	300	100	-	130
1014	700	350	0	0	-	130
1022	250	125	280	95	50	130
1021	600	300	0	0	-	130
1043	200	100	230	100	150	130
1042	400	200	300	80	-	130

Table A-2: Loads data

Bus	PD MW	QD MVAr	QSh MVAr	Voltage level kV
4022	-	-	-	400
4032	-	-	-	400
4043	-	-	200	400
4044	-	-	-	400
4045	-	-	-	400
4046	-	-	100	400
4061	-	-	-	400
2031	100	30.00	-	220
1011	200	80.00	-	130
1041	600	200.00	200	130
1044	800	300.00	200	130
1045	700	250.00	200	130
42	400	125.67	-	130
41	540	128.80	-	130
62	300	80.02	-	130
63	590	256.19	-	130
51	800	253.22	-	130
47	100	45.19	-	130
43	900	238.83	-	130
46	700	193.72	-	130
61	500	112.31	-	130

In this thesis, we assumed that 60% of the available electricity generation from each generator can directly go into a bilateral contract with different loads, and that the rest 40% of the available electricity generation will be offered in the spot market. Likewise, 60% of the total demand at a bus is entered in bilateral contract with different generators, and the rest of the demand will be bought from the spot market.

Reference

[1] CIGRE TF 38-02-08, Long Term Dynamics Phase II, 1995.

3 Regression Analysis

Regression analysis is concerned with describing and evaluating the relationships between a given variable '*y*', known as the *explained* or *dependent* variable and one or more other variables, '*x*', known as the *explaining* or *independent* variables [1].

Ordinary Least Square (OLS) is an econometric technique for calculating the regression equation that minimizes the sum of the squares of the error terms, *i.e.*, the differences between the observed values for the dependent variable and the predicted values for the dependent variable. Consider a function,

$$y = f(x) = \alpha + \beta_i x_i + \varepsilon \qquad \forall\ \mathrm{i} = 1, 2, ..., \mathrm{k} \tag{1}$$

In (A.1), the explaining variables are denoted by x_i (for i=1,…,k); β_i (for i=1,…,k) are the corresponding coefficients, and k is the total number of variables needed to explain the underlying relationship between y and x. ε is the error or noise term representing all those stochastic conditions beyond the control of the market participants, such as weather, generator outages, *etc.*

The OLS technique minimizes the square of the differences between the observed value and the predicted value for the explained variable given by (2) as follows:

$$\sum_{n=1}^{N} \left(y_n - \alpha - \beta_i x_{in} \right)^2 \tag{2}$$

N is the total number of observations. The goodness of the fit of the underlying relationship, as predicted by the model, is denoted by R^2 as given by (3):

$$R^2 = \frac{\text{Explained Sum of Squares}}{\text{Total Sum of Squares}} \tag{3}$$

From (3) it is evident that the higher the value of R^2 the better the model fits. The maximum value of R^2 is 1.

Reference

[1] G.S. Maddala, *Introduction to Econometrics*, 3rd Edition, John Wiley and Sons, 2001.